ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
BUREAU OF AIR

April 2005

Responsiveness Summary
for Public Questions and Comments on the Construction Permit Application from
Prairie State Generating Company

Site Identification No.: 189808AAB
Application No.: 01100065

TABLE OF CONTENTS

INTRODUCTION

Prairie State Generating Company (Prairie State) has applied for an air pollution control construction permit to build a 1,500 megawatt coal-fired electric power plant in Washington County approximately 5 miles east north east of Marissa, Illinois. The proposed plant would be a mine-mouth project, and the new mine would be referred to as the Prairie State Mine. The proposed project is considered a major source of air emissions and is subject to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21.

Upon review of comments received during the public comment period, and final review of the application and other relevant materials, the Illinois EPA has determined that the project meets the standards for issuance of a construction permit. Accordingly, on April 28, 2005, the Illinois Environmental Protection Agency (Illinois EPA) will issue a permit to Prairie State to construct the proposed facility. The facility must be constructed and operated in accordance with applicable regulations and the conditions of the permit.

Note: The permit that is being issued on April 28, 2005, takes the place of a previous permit issued by the Illinois EPA for the proposed facility on January 14, 2005. That permit was sent back to the Illinois EPA pursuant to an order from the Environmental Appeals Board at the USEPA.

DESCRIPTION OF PROPOSED PROJECT

The proposed power plant would have two pulverized coal boilers. In a pulverized coal boiler, the coal is ground (pulverized) to a fine powder immediately before being burned and is blown with primary combustion air into the boiler through a series of nozzles. Secondary air is blown into the boilers through other nozzles to complete combustion. The boilers would be a modern design, with features to enhance the plant's energy efficiency.

The boilers would be equipped with a multi-stage system to minimize and control emissions. The boilers would be equipped with low NOx burners and use good combustion practices to reduce emissions of nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic material (VOM). The add-on control train for each boiler would include selective catalytic reduction (SCR) for control of NOx, an electrostatic precipitator (ESP) for control of particulate matter (PM), wet flue gas desulfurization (WFGD), i.e., a scrubber, for control of sulfur dioxide (SO_2), and a wet electrostatic precipitator (WESP) for control of sulfuric acid mist and condensable particulate matter. The permit also includes provision for use of sorbent injection to control emissions of mercury, if effective control of mercury cannot be assured with "co-benefit" from the control devices for other pollutants. The exhaust from the boilers would then be vented through individual flues, one for each boiler, out a single 700-foot high stack.

COMMENT PERIOD AND PUBLIC HEARING

The Illinois EPA Bureau of Air evaluates applications and supporting materials for proposed projects and makes permitting determinations for sources of emissions to the atmosphere. A proposed project must appropriately address compliance with applicable air pollution control laws and regulations before a permit can be issued. Following its initial technical review of Prairie State's application and other relevant materials, the Illinois EPA Bureau of Air made a preliminary determination that the proposed project met the standards for issuance of a construction permit and prepared a draft permit for public review and comment.

The public comment period began on February 4, 2004, with the publication of a notice in the Nashville News. Initial notices of the public comment period were also published in the Sparta News-Plaindealer/New Athens Journal Messenger that same week. Additional notices were published in the Nashville News on February 11 and 18, 2004 and in the Sparta News-Plaindealer/New Athens Journal Messenger those same weeks.

A public hearing was held on March 22, 2004, at the Marissa High School in Marissa to receive oral comments and answer questions regarding the application and draft air permit. The comment period originally was scheduled to close on April 21, 2004, to receive written comments. The comment period was extended five times with the comment period ultimately closing on August 27, 2004.

AVAILABILITY OF DOCUMENTS

The permit issued to Prairie State and this Responsiveness Summary are available through the following means:

1. By viewing the documents at one of the following repositories:

Marissa Public Library
212 N. Main St.
Marissa, IL 62256-1344
618/295-2825

Illinois EPA
Collinsville Regional Office
2009 Mall Street
Collinsville, IL 62234
618/346-5120

Illinois EPA
1021 North Grand Ave, East
Springfield, IL 62794
217/782-7027

2. By contacting the Illinois EPA by telephone, facsimile or electronic mail:

Illinois EPA
Bradley Frost, Office of Community Relations Coordinator
888-372-1996 Toll Free – Environmental Helpline
217-782-7027 Desk line
217-782-9143 TDD
217-524-5023 Facsimile
brad.frost@epa.state.il.us

3. By accessing the World Wide Web at www.epa.state.il.us/public-notices/general-notices.html or www.epa.gov/region5/air/permits/ilonline.htm (for the second address look under All Permit Records, PSD, New).

To obtain a printed copy of the documents by mail and free of charge, please contact Brad Frost at the contact information listed in #2 above.

APPEAL PROVISIONS

This Permit authorizes construction of emission sources and air pollution control equipment associated with the proposed mine-mouth coal-fired power plant. Authorization is also granted for construction with respect to the PSD rules. As a general matter, individuals who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board (EAB) to review the PSD provisions of the issued Permit. The PSD approval becomes effective on June 8, 2005, as authorized under the provisions of 40 CFR §124.15, unless a petition for review is filed with the EAB in accordance with the provisions of 40 CFR §124.19. Any such petition must be received by the EAB on or before June 8, 2005. An appeal request may be filed with the EAB by regular mail by sending it to the following address:

U.S. Environmental Protection Agency
Clerk of the Board
Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

Questions regarding filing or other appeal requirements should be directed to the EAB at 202-233-0122 or its web site at www.epa.gov/eab.

GENERAL RESPONSE TO COMMON PUBLIC CONCERNS

The proposal to issue a permit for the construction of the Prairie State coal-fired power plant has generated a variety of comments from the public and a number of environmental organizations. The comments that were submitted were helpful to the Illinois EPA in the decision making process and these comments were fully considered by the Illinois EPA prior to issuing the permit on January 14, 2005. However, the Illinois EPA did not make the Responsiveness Summary available until after the issuance of that permit. The Sierra Club and others filed a Petition with the EAB alleging, in part, that the Illinois EPA committed procedural error by failing to simultaneously issue that permit and the Responsiveness Summary. The EAB remanded that permit back to the Illinois EPA on March 25, 2005. The EAB found that the Illinois EPA "must reconsider and reissue the final permit decision, after due consideration of comments received and of the response to comments document, exercising its discretion as appropriate and in accordance with the facts and the law". In re Prairie State Generating Station, PSD Appeal No. 05-02.

In addition, the EAB encouraged the parties to negotiate a solution to the issues set forth in the Petition. The Illinois EPA subsequently met with representatives of a number of the previous Petitioners. These discussions also facilitated changes in the issued permit, as compared to both the draft permit and the earlier permit issued on January 14, 2005.

In accordance with the EAB's order, the Illinois EPA has again fully considered comments prior to issuing this permit on April 28, 2005. This Responsiveness Summary is based on analyses completed prior to permit issuance, which analyses formed the bases for the permit decision and the terms and conditions of the permit.

A major concern from the public about the proposed plant was that the plant will be "dirty", similar to existing coal fired plants because it does not have "state of the art" pollution controls. Actually, Prairie State will be much cleaner than existing coal-fired power plants and will be equipped with modern pollution control devices. Technologies that might be considered "state of the art" for purposes of this comment include Integrated Gasification Combined Cycle (IGCC) technology. The Illinois EPA has examined the status of IGCC technology at the present time. While various claims have been made that the technology is available for the proposed plant, they do not survive close scrutiny. While IGCC is expected to be the next generation of technology for coal-fired power plants and has been demonstrated by several projects supported by the United States Department of Energy (USDOE), it is still a developing technology that is not yet fully mature. IGCC technology is significantly more expensive and has not demonstrated the same level of dependability as traditional boiler technology. These factors are obstacles to commercial acceptance, i.e., financing, of the proposed plant with IGCC technology. It is not appropriate for the permit to require use of a technology by the proposed plant that is not yet sufficiently developed to be commercially accepted.

Another comment was that the plant would emit an unacceptable level of ozone (smog) forming pollution. The Illinois EPA has evaluated the effect that the ozone forming emissions will generally have on the air quality of Illinois and specifically the Greater St. Louis Area. While the plant would contribute to background levels of ozone affecting the Greater St. Louis Area, substantial improvements in air quality have occurred in the St. Louis area. For example, St. Louis is now attainment for the one-hour ozone standard. Improvements in air quality will continue to occur even with the addition of the proposed plant because the emissions of the proposed plant would be well controlled and Illinois' power plants have been and will continue to be subject to regulations such as Illinois' NOx Trading Program and USEPA's Clean Air Interstate Rule (CAIR), that restrict their overall emissions as a group.

A major concern was the potential impacts of the emissions of the proposed plant on public health. The health impacts of coal-fired electric power plants has been the subject of considerable scientific scrutiny. Power plants do emit pollutants that in sufficiently high concentrations can have health effects, particularly for people suffering from asthma, chronic respiratory diseases or heart disease. Some studies have found that emissions from existing coal-fired power plants in Illinois do contribute to these effects at levels that can be predicted mathematically. However, those studies do not demonstrate that new power plants, like the proposed plant, pose a significant risk to public health individually. Indeed, having an adequate, reliable and affordable supply of electricity is also essential to modern society, and to the health and well-being of the public. Rather, the purpose of those studies is to influence public policy toward reducing the emissions and any associated health impacts from existing "grand-fathered" power plants, many of which are over forty years old. As such, one goal of those studies is to have these existing power plants upgraded to approach the levels of emission control that would be present at the proposed plant.

Another concern was that the proposed plant will be a source of mercury emissions which will pollute the state's water bodies and in doing so make fish unsafe for consumption. Prairie State will be subject to applicable federal regulations for control of mercury emissions. The proposed permit requires the plant to be equipped with modern emission controls and to emit only a fraction of the mercury emitted by existing plants.

Another general comment was that the State of Illinois should clean up existing coal fired power plants. This goal may be achieved by construction of new, modern, well-controlled coal-fired power plants, like the proposed plant, that over time displace existing plants and reduce adverse health impacts from use of coal for power generation without accompanying modern control technology.

A final concern is that the construction of the plant will threaten jobs and economic development in Illinois. The plant will not generally pose a threat to jobs and economic development in Illinois and should act to support and enhance Illinois'economy as it provides reliable and affordable electricity. Any potential effects that the plant would have on future construction of other new projects due to consumption of air quality increment would only impact a proposed new major source of emissions in the immediate vicinity of the plant. The construction and operation of the plant, including the associated coal mine, will directly create and provide jobs in construction, mining and operation of the plant. However, it should be recognized that many of these jobs probably represent employment for people already in the area, as other construction projects are completed and businesses close. In this regard, the proposed plant is important for the regional economy as it maintains and supports the current economy, rather than it will lead to growth in the economy. It should also be fully understood that consideration of economic benefits from the plant did not influence the Illinois EPA's decision on this project because the Illinois EPA cannot consider consequences positive or negative that do not relate to the emissions and environmental impactsfrom a proposed source. The decision whether to grant a permit is a legal and technical one, based on compliance with applicable environmental laws and rules.

QUESTIONS AND COMMENTS WITH ILLINOIS EPA RESPONSES

General Comments on the Proposed Plant and Its Impacts

1. This proposed plant will use advanced emission control technology that would make it among the cleanest coal-fired power plants in the nation. The plant would be cleaner than the existing averages for US coal-fired power plants, Illinois coal plants and future emission limits for coal plants that have been proposed.

The Illinois EPA agrees with this comment.

2. The emission levels allowed by the draft permit would be among the highest of new coal plant permits issued in the last 15 months. Permits for new coal plants in Wisconsin and in West Virginia have much lower emission limits for SO_2, NOx, and mercury, among other pollutants.

This comment reflects an overly simple and misleading comparison of those other plants with the proposed plant, as the comment ignores the characteristics of coal burned at different plants. To appropriately compare coal-fired power plants, one should consider the coal supply for the power plant, which has a critical role in determining the emissions levels that are achievable, especially for sulfur dioxide (SO_2). When this is factored in, the performance of the proposed plant is equal to or better than that of other new coal-fired power plants.

3. The amount of pollution from the proposed plant is higher than would be suggested by looking at emission rates alone. The plant is relatively inefficient compared to other new pulverized coal plants, and far less efficient than plants based upon IGCC technology. Together, these factors mean that the proposed plant will emit unacceptably high levels of air pollution.

This is not correct. The efficiency of the proposed plant is similar to that of other new coal-fired power plants. While IGCC technology should be more efficient, IGCC technology is still a developing technology for power generation. It cannot yet be considered viable for this privately financed power plant project that is not guaranteed a revenue stream or return on investment. Also, the emissions of the proposed plant will not threaten current air quality.

4. This is a bad time to build a new coal-fired power plant. Across the country, new coal-fired power plants are being proposed while ambitious clean coal technology programs are in their infancy. Technologies like IGCC, which would improve efficiency and reduce emissions of greenhouse gases, are not considered commercially viable as yet but may be shortly. It would be a huge shame if a whole new generation of coal-burning plants came on-line just before more effective clean coal technologies hit their stride.

The continuing development of clean coal technology does not provide a legal basis to refuse to issue a permit for the proposed plant. Applications for proposed plants must be reviewed based on current regulations and circumstances. The Illinois EPA is not allowed to nor is it capable of predicting what future regulations will require or when new control technology will

become viable and what it will achieve. While the Illinois EPA is optimistic that IGCC will become financially viable for power generation in the not too distant future, experience with the development of IGCC technology, as it has been occurring over the last 15 years or more, suggests that it could also take much longer. A delay in the development of IGCC would pose greater concern if Illinois were currently seeing plans to replace most of its existing coal-fired generating capacity. This is not the case, as a relatively small number of new plants are proposed. The current proposals for new coal-fired plants may appear to be of more consequence than they really are because it is has been almost 25 years since the last new coal-fired power plant was built in Illinois.

5. New technology is also only in the testing phase for control of mercury emissions.

Equally important, efforts are underway for existing control technologies to refine and apply <u>established</u> approaches to control of mercury so that they are most effective in controlling emissions, negative side-effects for the disposal of coal combustion residue are avoided, and control costs are reasonable.

6. When the costs of this plant are considered, does the Illinois EPA consider the health costs of treating coal miners' injuries and illnesses and treating the illnesses caused by breathing polluted air and eating contaminated fish.

Permitting of a proposed source does not entail a direct cost-benefit analysis, considering the costs of the source, the estimated value of the benefits it would provide, and the estimated costs associated with its negative impacts. However, the potential negative air quality impacts of a source are directly addressed by the emission limits and standards and other regulatory requirements that apply to the source to minimize any negative air quality impacts. A construction permit can only be issued for a proposed source if it would comply with these requirements, irrespective of the economic benefits that the source would otherwise be expected to provide. In terms of air quality, this approach is both reasonable and necessary because air quality is the combined result of the emissions of many sources and the related actions of many individuals.

7. This area is already subjected to a major source of emissions with the Baldwin power plant, so that the proposed plant should not be approved.

This is not a reasonable or legally supportable basis to deny a permit for the proposed plant. One of the functions of the permit process for a proposed major source is to consider the combined effect of that source and existing sources already in the area as necessary to confirm that the proposed plant will not cause or contribute to violations of air quality standards. The review of the proposed source confirms that this would not be the case.

In addition, on March 7, 2005, it was announced that settlement discussions between USEPA and others with Dynegy concerning the Baldwin power plant had been successfully concluded with the development of a Consent Decree, which is currently filed before the local United States District Court. This decree, once ratified by the court, would "lock" the Baldwin plant into operating at current emission levels, which are well below applicable standards, including

operating its two selective catalytic reduction (SCR) systems for control of nitrogen oxides (NOx) year round. The decree would also require that emissions of SO_2 and particulate matter from the plant be further reduced with the installation of additional equipment to control emissions on a schedule that ends on December 31, 2012. The decree also contains emission control requirements for the four other coal-fired power plants in Illinois owned by Dynegy.

8. Prairie State seeks permission to emit, annually, over 280 pounds of mercury, over ten thousand tons of fine particle and ozone-forming pollutants, and millions of tons of greenhouse gases, into the atmosphere. These are quantities that constitute "air pollution," as addressed by 35 IAC 201.141, so that the Illinois EPA cannot issue a permit for the proposed plant.

State regulations do not define air pollution in terms of the amount of emissions from a source, but in terms of the effects of emissions of a source and whether they would be or are in compliance with applicable regulatory requirements. The application shows that the proposed plant would not cause or contribute to air quality violations and would comply with applicable regulations. Accordingly, the proposed plant cannot be considered to be causing air pollution in the manner that is prohibited by 35 IAC 201.141.

9. At greatest risk from more soot and smog are children and the elderly, especially those with asthma, who live in Washington and surrounding counties. The levels of soot and smog in the Metro East area are already unsafe to breathe without the additional emissions from the proposed plant. Prairie State should take into account the cumulative effects of the many pollutants coming from the area into the Greater St. Louis area.

The air quality analyses performed for the proposed plant show that it would not have a significant impact on air quality in the immediate area near the plant. As a general matter, as it is located in southern Illinois, it would have some contribution to background levels of air quality affecting the Greater St. Louis Area, where air quality levels for ozone and particulate are still at levels of concern, particularly for those who are most sensitive to air pollution. However, substantial improvements in air quality have occurred in the St. Louis area. For example, St. Louis is now attainment for the one-hour ozone standard. Improvements in air quality will continue to occur even with the addition of the proposed plant. This is because the emissions of the proposed plant would be well controlled and because Illinois' power plants have been and will continue to be subject to regulations such as the NOx Trading Program, the Acid Rain Program and the Clean Air Interstate Rule (CAIR), that restrict their overall emissions as a group. To the extent that the proposed plant accelerates or facilitates replacement of existing coal-fired power plant capacity, the proposed plant could even contribute to improvements in air quality in the Greater St. Louis Area.

10. The proposed plant will harm rivers and wildlife.

The potential impacts of the proposed plant on the environment, including rivers and wildlife, are addressed by applicable regulations and the project-specific review during permitting. These serve to protect the surrounding environment from harm from the proposed plant.

11. For people living within two to three miles of the plant, a significant reduction in the visual quality of the landscape and natural beauty of the night skies will be a tragic reality. The beauty of this area is a primary reason why many people, including myself, have chosen to live here.

These concerns dealing with the site selected by Prairie State for the proposed plant are beyond the scope of the Illinois EPA's authority in permitting.

12. People living within a few miles of the plant will be affected by noise from the plant.

Noise from the proposed plant must be controlled to within noise levels set by State rules, which were developed to protect people from nuisance noise.

13. The plant's SO_2 and NOx emissions will have serious detrimental impacts as they contribute to fine particulate matter in the atmosphere.

The proposed plant's contribution to fine particulate is minimized by the stringent level of control required for emissions of SO_2 and NOx.

In addition, the plant's contribution to fine particulate matter air quality is addressed by USEPA's Clean Air Act Interstate Rule (CAIR), which has been finalized and was signed by USEPA Administrator Steven Johnson on March 10, 2005. This rule requires a substantial overall reduction in SO_2 and NO_x emissions of coal-fired power plants, by setting caps on total emissions of SO_2 and NO_x from plants in 28 states including Illinois. As a result, the emissions from the proposed plant will not represent an increase in the overall loading of SO_2 and NO_x emissions to the air.

14. Southern Illinois' high unemployment was caused by an economy based on coal. The solution to this problem will not be through the construction of the proposed plant, but through breaking the coal paradigm and finding new ways to produce energy.

The proposed plant does represent something new. It would be the first new coal-fired power plant built in southern Illinois in almost 25 years. It would be specifically designed to burn local high-sulfur coal, with modern control devices to effectively reduce emissions.

15. Supporters of the plant talk of mining and construction jobs. Five hundred jobs is poor justification for the pollution from the proposed plant.

The number of jobs provided by the proposed plant was not a factor considered by the Illinois EPA in deciding whether to issue a permit for the proposed plant nor could it be under applicable regulations. While the Illinois EPA did not consider the role of the proposed plant in providing employment when deciding whether to issue a permit, the Illinois EPA did appropriately consider and review, as part of the growth analysis required under the PSD rules, the potential for air quality impacts as a result of growth associated with the proposed plant.

16. As Selective Catalytic Reduction (SCR), used to control NOx emissions, also facilitates the production of sulfuric acid mist, it is a cause for concern.

The potential increase in a boiler's emissions of sulfuric acid mist is a factor that must be considered with an SCR system. While SCR does facilitate the conversion of a small fraction of a conventional coal-fired boiler's SO_2 emissions into sulfuric acid mist, this is a not an entirely new phenomenon. Even without an SCR, some SO_2 emissions are already converted to and emitted as sulfuric acid mist. Then, in the atmosphere, most of a boiler's SO_2 emissions are gradually converted to sulfuric acid before they react further to form sulfates.

The issue for SCR is whether the potential side effects on sulfuric acid mist emissions have been recognized and properly considered in the design of the SCR system. This is now routine and SCR systems have been installed on many existing utility boilers, providing effective control of NOx emissions without unacceptable side effects from sulfuric acid mist emissions. In addition, for the boilers at the proposed plant, wet ESPs will be used to specifically control emissions of sulfuric acid mist.

17. The proposed plant would be subject to the NOx Trading Program. Are there enough NOx allowances set aside for new sources for both Indeck and Prairie State? Given this program, will it be possible to construct all of the power plants proposed in Illinois?

The new source set aside was not developed to accommodate new coal-fired power plants, i.e., it does not have enough NOx allowances for <u>either</u> the Indeck or Prairie State projects. During their initial years of operation, both companies would need to obtain allowances from existing plants, which would reflect reductions in NOx emissions at those plants. Likewise, it would only be possible to construct all the new power plants currently under consideration for Illinois if there are even more reductions in the NOx emissions from existing plants. However, given the low rates of NOx emissions from new plants and how the NOx Trading Program functions, the program will not prevent the development of new power plants.

The NOx Trading Program sets a cap on seasonal NOx emissions from power plants. The summertime emissions of NOx from Illinois' existing coal-fired power plants have had to be reduced, by over 50 percent, to comply with this cap or "budget," which is related to Illinois' federally approved plan for complying with the one-hour ozone air quality standard. The NOx emissions of existing power plants will have to be further reduced as needed to make room for new power plants, so that overall NOx emissions stay within the cap. This may occur from additional NOx controls on certain plants or reduced utilization or shutdown of other existing plants. The actual reductions will be determined by market forces so that the older, more expensive to operate and higher emitting plants will likely provide the further NOx reductions and overall costs are minimized. However, as new plants will be less costly to operate and emit far less, there should be adequate allowances available for any new plants. Instead, another force or incentive will be applied to reduce or shut down older plants.

The new source set aside does not alter these basic mechanics of the program. It sets aside a fairly small amount of allowances, up to 614 tons, for the first three years in which a new plant, like Prairie State, would operate. This assures that some allowances are readily

available for a new plant until, after three years of operation, the operator of a new plant is allocated a *pro rata* share of NOx allowances based on actual utilization data. Even then, during the period when the new source set aside allowances are available to the operator of a new plant, the operator of a new plant must pay for the allowances at the price established in the preceding season.

18. A permit should not be issued to Prairie State because it does not intend to build the proposed plant. Instead, Prairie State has indicated that it plans to obtain the necessary permits and then sell to another entity that would build and operate the plant. Without a buyer committed to the project, there is no assurance that construction will commence within 18 months should a permit be issued. USEPA has held that a source cannot "sit on" a permit without some definite plans to use it. See In re Monroe Electric Generating Plant, Order in Response to Title V Petition 6-99-2, Note 11.

No information has been provided to the Illinois EPA that indicates that Prairie State is not committed to this project, as alleged by this comment. Moreover, even if Prairie State intended to act solely as a "developer," as suggested by this comment, this would not be improper. By its actions in pursuing a permit for the proposed plant, a lengthy and costly enterprise, Prairie State has demonstrated an ample commitment and intention to build the proposed plant. If circumstances change so that Prairie State is unable to begin construction of the project in a timely manner, the permit would expire as a matter of rule. The circumstances of the Monroe Electric plant, which dealt with an operating permit for an existing plant that had been idle for over ten years, are misapplied to this situation.

BACT – Alternatives to Proposed Plant

19. Prairie State has not considered reasonable alternatives to the proposed plant. For a major project subject to PSD, the Clean Air Act requires the permitting agency to consider alternatives to a proposed project. This is because the Clean Air Act requires that interested parties be given a reasonable opportunity to comment on four issues: " …the air quality impact of such source; alternatives thereto; control technology requirements; and other appropriate considerations." In combination with the permitting authority's obligation to respond to all reasonable comments, the permitting agency must consider alternatives "to such source," including alternate sites, when appropriately raised by the public. Why else would Congress require that interested parties have an opportunity present comments on "alternatives" to the proposed source?

The plain language of the Clean Air Act contemplates a public hearing in which interested parties are provided an opportunity to make oral comments on, among other matters, alternatives to the proposed source. The language does not, as this comment suggest, require a permitting authority to conduct an analysis or otherwise require from an applicant, information regarding alternative sites, locations or project types. The language merely establishes certain parameters for public participation in the PSD permitting process, confirming the right of the public, including individuals who may be interested in developing other projects in an area, to comment on alternatives to a proposed source during the

permitting process. While the provision requires that a broad range of public comment must be allowed in the permitting process, it cannot be assumed that Congress intended that a wide–ranging analysis of alternatives must be conducted by the permitting authority.

Moreover, neither the Illinois Environmental Protection Act nor the Clean Air Act dictates the type of plant that a source may propose to build. The USEPA has frequently observed that the BACT requirement of the PSD program does not compel a permit applicant to change the basic nature of a proposed plant in order to lower the associated emissions.

20. The Illinois EPA must consider alternate locations and alternate size plants to Prairie State's proposal. Based on the proposed location, 1.8 miles upwind of the Greater St. Louis nonattainment area, secondary particulate formed from the plant's emissions will have serious detrimental impacts as it contributes to illness and premature mortality. In addition, Prairie State's own analysis shows that the area is exceeding the SO_2 NAAQS and will violate the PM10 NAAQS. Prairie State's emissions present a serious threat to public health in an area where people are already being affected by poor air quality.

The health impacts of coal-fired electric power plants has been the subject of considerable scientific scrutiny. Power plants do emit pollutants that in sufficiently high concentrations can have health effects, particularly for people suffering from asthma, chronic respiratory diseases or heart disease. Some studies have found that emissions from existing coal-fired power plants in Illinois do contribute to these effects at levels that can be predicted mathematically. However, air quality modeling analyses show that the plant will not have noticeable effects on the air quality in Washington County and surrounding areas. This evaluation, which is performed using computerized dispersion models, shows that the concentrations of these pollutants in the air would continue to be below the NAAQS, which are established by USEPA to protect human health and welfare. Indeed, having an adequate, reliable and affordable supply of electricity is also essential to modern society, and to the health and well-being of the public.

21. Since most new power plants in Illinois, including the proposed plant, are no longer regulated utilities subject to approval by the Illinois Commerce Commission (ICC), the BACT process under PSD takes on an especially important purpose. In particular, the BACT process is arguably the only remaining opportunity to consider whether a new coal-fired plant should be built at all.

Such action is only possible if it is supported by the Clean Air Act and the federal PSD program. The federal PSD program, as developed by USEPA, does not identify or provide for any difference in BACT determinations between states that have and have not deregulated the generation of electricity. At the State level, the Illinois EPA does not have the legal authority to deliberate upon the "public necessity" of power plants, in the manner formerly exercised by the Illinois Commerce Comission. Introducing the consideration of need into the BACT process would be in direct contradiction to the action taken by the Illinois Legislature to deregulate the generation of electricity in Illinois, as addressed by this comment.

22. The proposed plant is not necessary because Illinois has surplus generating capacity. The

proposed plant is not needed by the people of Illinois or the nation.

This comment is outside the scope of the Illinois EPA's review of the proposed plant. However, if the electricity from the proposed plant were not needed, as broadly claimed by this comment, the proposed plant would not be built, as there would be no demand for the electricity that it would produce.

23. Because the function of a single power plant typically is to add to a common pool of electricity supply, the threshold question of need should not be ignored in deciding whether to issue a permit for the proposed power plant. Power plants deserve particular scrutiny because of their tremendous size, longevity, capital and operating costs, demands on fuel supplies and transmission lines, and other impacts. The threshold question in considering any prospective new power plant is why the plant should be constructed at all. Clearly there is not a need for additional electric-generating capacity in Washington County, itself. Then from an air pollution perspective it is preferable to rely on energy efficiency and renewable energy than to construct a new power plant. In the absence of such review by another government agency, this responsibility falls to Illinois EPA.

The Illinois EPA does not have the authority to consider need when evaluating the permit application. Also, while Illinois currently may have adequate generating capacity to meet the demand for power, this does not mean that Illinois would not benefit from development of a new, cleaner, coal-fired power plant, such as the proposed plant. In addition to benefits in terms of lower emissions, Illinois would benefit from a new plant as it would be more efficient than older plants and would use local coal contributing to the state's economy. Looking ahead, even with conservation and efficiency improvements, electricity needs will increase in the future. Given that a new power plant project takes a number of years to complete, any such discussion must include what generating capacity will be needed years from today.

24. The Illinois EPA must consider energy efficiency and clean energy sources, such as wind turbines, prior to issuing a permit for the proposed plant. As part of the review of the proposed Elm Road plant, the State of Wisconsin considered alternatives, including energy efficiency and wind-turbines. It found that wind power could be a significant component of an integrated resource alternative that could substitute for a portion or all of the proposed plant. Wisconsin ultimately rejected these measures, which is the subject of an ongoing appeal.

The Illinois EPA does not have the authority to consider alternatives to a proposed power plant, like wind turbines or energy efficiency measures, as part of its review of an application for a proposed plant. The fact that such measures could be considered under Wisconsin law, notably by Wisconsin's Public Service Commission in its multi-faceted role in the review and approval of the proposed Elm Road plant, which would be associated with a regulated utility, does not demonstrate that the Illinois EPA can consider such matters.

25. When it comes to electricity generation, wind energy and solar energy should be considered as BACT. Prairie State is not using BACT.

The Illinois EPA does not have the legal authority to require Prairie State to develop such a plant. However, the Illinois EPA certainly recognizes the air quality benefits of wind power and solar energy and encourages companies to pursue such projects, but it should be recognized that development of a wind-power plant is a major undertaking. Moreover, a wind power plant would not be a substitute for the proposed plant. Wind power is dependent on the strength of the wind, which is neither dependable nor consistent. On an annual basis, a wind plant in Illinois would have an annual capacity factor of at most 25 percent. This is equivalent to being available for at most 6 random hours each day. In contrast, the proposed plant is intended to be available at its full capacity for up to 24-hours each day.

At this time, the technical and practical obstacles for a utility-scale solar power make such an endeavor impractical as an alternative to traditional power plants. Solar energy also would not be a substitute for the reliable power provided by the proposed plant.

26. The need for the proposed plant might change if Illinois were to move forward and adopt stringent rules to require Illinois' existing coal plants to either reduce emissions or shut down. Otherwise, in the absence of a demonstrated need, the Illinois EPA should not issue a permit for the plant.

The status of rules for existing power plants and the permitting of the proposed plant are separate matters and cannot be linked in the manner suggested in this comment. In addition, as noted by this comment, when more stringent requirements for emissions of coal-fired power plants become effective, either on a state or national level, it will create an additional incentive for existing plants to reduce operations or shut down.

27. The Illinois EPA should consider whether additional energy efficiency measures could minimize or even eliminate altogether the need for the proposed plant. Such measures would also reduce other environmental impacts from the proposed plant, such as use of water and wastewater discharges.

Although the Illinois EPA recognizes the benefits of energy efficient measures in the residential, commercial and industrial sectors, and encourages companies to pursue such projects, the Illinois EPA does not have the legal authority to require these sectors to consider additional energy efficient measures as part of these analyses.

28. The proposed plant is not needed. Slight increases in energy efficiency could easily eliminate any perceived need for this plant. New standards for air conditioning, lighting, and other electrical use are a cleaner, far more environmentally and health friendly alternative. These are not even in the equation but they should be.

The possibility of new efficiency standards for air conditioning, lighting, and other electrical use is not a relevant factor that the Illinois EPA can consider in the permitting of the proposed plant. The permitting of the proposed plant is governed by state and federal law and is based on whether the application for the plant demonstrates that it would comply with established environmental standards and criteria that are applicable to the proposed plant.

29. The proposed plant is not needed. Slight increases in efficiency of generation as provided by new technologies like IGCC would easily eliminate any perceived need for the proposed plant.

IGCC would not eliminate the need for new power plants, it would only change the type of technology used at those plants. In addition, the Illinois EPA has considered whether the proposed plant should use gasification technology (Integrated Gasification Combined Cycle or IGCC) and has required Prairie State to conduct a detailed evaluation of the potential use of this technology. The Illinois EPA concluded that gasification, while technically feasible, is also still a developing technology for power generation. As a result, the uncertainty about the performance and cost of this technology would prevent the plant from being developed with gasification technology. Given these findings, the Illinois EPA does not have the authority to require Prairie State to use coal gasification technology at the proposed plant.

30. If the electricity were needed, there are many options that could be used to generate it. Wind, active solar, geothermal, hydro, biomass, fuel cells and other proven technologies can provide electricity without the environmental and health consequences that accompany burning coal.

The Illinois EPA recognizes the air quality benefits of wind and solar power and, in the same token, recognizes the benefits of hydro, biomass, and fuel cells. As already explained, the Illinois EPA does not have the legal authority to require Prairie State to consider or utilize these alternative technologies.

31. If the true cost of burning coal were included in the sale price of coal, coal would no longer be an option for generating electricity. Costs like health costs to humans who must breathe coal's effluent, and environmental degradation and destruction, habitat destruction, thermal pollution from water outfalls, black lung for coal miners, and groundwater that is contaminated from the deposition of combustion wastes are not listed on this balance sheet. They should be.

Power plants do emit pollutants that in sufficiently high concentrations can have health effects, particularly for people suffering from asthma, chronic respiratory diseases or heart disease. Some studies have found that emissions from existing coal-fired power plants in Illinois do contribute to these effects at levels that can be predicted mathematically. For purposes of the BACT analysis, the Illinois EPA appropriately evaluated the effective controls for the proposed plant. New coal-fired power plants, by selection of coal, efficient combustion, and add-on control systems, are designed to minimize and control emissions. As technology continues to improve and evolve, coal will become an even cleaner fuel.

BACT – Alternative Combustion Technologies

32. Prairie State's analysis does not reflect BACT because it failed to consider cleaner processes such as CFB and IGCC, cleaner power generation processes that would lessen the plant's emission and air quality impacts. The definition of "BACT" expressly requires a "taking into account" alternatives such as "production processes," and "innovative fuel combustion techniques." A company proposing a coal-burning power plant must address the alternative combustion techniques, such as CFB and IGCC.

Prairie State addressed these alternative coal-based technologies in its application and the Illinois EPA considered them in setting BACT for the proposed plant.

33. Prairie State's BACT analysis failed to seriously consider the possibility of using CFB boiler technology as a less-polluting combustion technology. CFB boilers are clearly available, as it is currently in use at other power plants in the U.S. The control technology being proposed for this plant is not BACT when better technology for power generation, i.e., CFB boilers could be used.

Prairie State considered CFB technology. Upon close review, CFB boilers cannot be considered a less polluting combustion technology as compared to the pulverized coal technology required of the proposed plant. This technology does not have lower overall emissions and NOx emissions are higher than from pulverized coal boilers. In addition, CFB is a marginal technology for the proposed plant. CFB technology has not been demonstrated for boilers as large as those proposed for Prairie State, so that a comparably sized plant using CFB boilers would have five or six separate boilers, instead of two.

34. Boilers using a super-critical or ultra super-critical steam cycle would be more efficient, with less emissions per megawatt (MW) of electrical output than the proposed boilers for the plant, which would have a sub-critical steam cycle. Super-critical boilers are now possible because of continuing advances in the metallurgy of steel, better management of steam water chemistry, and other aspects of boiler design. The improvements in efficiency pay for the relatively small increase in capital cost of the boiler with this advanced technology. However, the absence of coal washing prevents use of this technology by the proposed plant.

Super-critical boiler technology, a specific form of pulverized boiler technology, would be preferable for both Prairie State and the environment, as it would generally improve overall efficiency of the plant as described in this comment. However, the use of super-critical boilers involves availability of appropriate materials and a design that allows reliable operation at higher temperature and pressures. Prairie State reports that it is investigating these issues with potential suppliers of the boilers. The permit would not preclude construction of super-critical boilers in the event that boiler suppliers can adequately answer the technical issues posed for this technology and provide the necessary guarantees to enable the financing of the proposed plant. The use of such technology would not affect the BACT determination for the coal-fired boilers as BACT limits are expressed in terms of the heat input to the boilers, i.e., lb/mmBtu.

35. Under BACT, Prairie State must identify all available technologies, including the most stringent, and must provide adequate justification for dismissing any of the technologies. IGCC using washed Illinois No. 6 coal is an especially attractive BACT option for this project. To conduct a proper BACT analysis, Illinois must thoroughly evaluate all available control measures including in particular, "innovative fuel combustion" techniques," i.e., coal gasification. IGCC should be seriously considered because any new power plant will be in operation for many decades.

Prairie State evaluated IGCC technology in its application and the Illinois EPA considered it as part of its BACT determination. Upon review, the Illinois EPA found that while IGCC is technically feasible, it is not appropriate to require that IGCC technology be used for the proposed plant, as previously explained.

36. The Illinois EPA improperly dismissed IGCC as a technology that is not viable for the proposed plant. "IGCC is still a developing technology. As a result, the handful of existing IGCC plants have received substantial grants from the US Department of Energy (USDOE) and IGCC technology cannot be considered a commercially viable technology. The higher costs and the uncertainties associated with IGCC would prevent the proposed plant from being developed. At the present time these factors would also likely preclude use of IGCC for other similar power plant projects being developed primarily with private (non-governmental) financing." Prairie State submitted a report from SFA Pacific that found that IGCC was not technically feasible for this project.

The Illinois EPA did not dismiss IGCC technology as not being technically available or being technically infeasible, as suggested by this comment.

37. IGCC was improperly evaluated as the SFA Pacific report concluded that IGCC emissions were similar to a pulverized coal boiler. However, IGCC achieves significantly lower emission rates than those of pulverized coal boilers, as shown by the emissions of recently permitted IGCC plants, which have lower emission rates than those proposed by Prairie State.

Significantly lower emission rates are certainly the promise of IGCC technology. However, this has not been demonstrated by the IGCC development projects supported by USDOE. In addition, emissions performance is only one aspect of the final evaluation of a candidate control technology for use as BACT, which also may consider economic impacts. This is the critical aspect of IGCC technology that the Illinois EPA relied upon in determining that IGCC cannot be required as BACT for the proposed plant.

38. Most of the analysis in the SFA report is irrelevant because the IGCC plant would operate on washed, not unwashed, Illinois No. 6 coal. The unwashed coal would have an ash content of around 23%. Washing the coal dramatically lowers the ash content to levels that IGCC plants routinely process. By basing the analysis on unwashed coal, the SFA report created a false feasibility issue. The SFA report should not be relied upon for its conclusions about projected IGCC emissions.

Coal washing is not a significant factor in the comparison of IGCC technology and pulverized

coal boilers, as claimed by this comment.

39. IGCC was improperly evaluated economically. The SFA Pacific report concluded, separate from other aspects of IGCC, that in any case financing would not be available for an IGCC plant from private lenders so that IGCC plants can be financed. However, the SFA report omits certain information and newer information on "limited recourse financing."

The information accompanying this comment, describing limited recourse financing for IGCC projects in Europe, does not demonstrate that coal-based IGCC plants in the United States can be privately financed. First, it addresses a different type of IGCC plant, i.e., IGCC plants using heavy petroleum materials as feedstocks, with backup diesel fuel for the turbines. Second, it addresses project financing relative to the circumstances present in Europe. Finally, the information does confirm that project risk is a critical factor in successfully obtaining financing for a project using IGCC technology.

This comment highlights a critical issue for the commercial use of IGCC technology for power generation. This is the development of new forms for financing, supported by appropriate regulations, that allow the risks associated with IGCC technology to be shared and managed. In addition to the technical aspects of IGCC technology, USDOE and others are concerned about developing an understanding of these financial obstacles and overcoming them. Otherwise, the real or perceived risk from use of IGCC technology for a project like the proposed plant is too large for current investors, especially when it adds to the financial risk associated with constructing a new large coal-fired power plant, when one has not been financed in the United States in the last 15 years.

40. My analysis comparing IGCC (using a washed Illinois No. 6 coal) to the proposal by Prairie State shows that the IGCC plant would emit significantly less than the proposed plant. The average cost effectiveness of an IGCC plant and the proposed plant are also virtually the same.

Above all, the analysis accompanying this comment shows that an IGCC plant would have a cost, expressed as an annual operating cost that is significantly higher than the cost of the proposed plant. A major factor in this additional cost is the need for a spare gasification reactor train needed to facilitate enhanced reliability of the IGCC plant. IGCC is commonly recognized as having a capital cost that is at least 20 percent higher than that of pulverized coal boilers. This situation is compounded by doubts about reliability of performance due to the limited and checkered track record of IGCC pilot projects, which make recovery of investment uncertain in the absence of governmental guarantees or subsidies. While efforts are underway to address these obstacles to IGCC technology, these efforts have not yet moved on to concrete solutions to these obstacles. For examples of these efforts, refer to *An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry*, DOE/NARUC Partnership for Advanced Clean Coal Technology, March 2004, and *Deploying IGCC in the Decade with 3Party Covenant Financing*, William Rosenberg et al, July 2004.

40a. IGCC technology is appropriate for the proposed plant because new power plants using

IGCC technology are being proposed elsewhere by companies other than Prairie State.

This does not demonstrate that IGCC technology is available for the proposed plant nor that IGCC is generally available. When a new technology, like use of IGCC for coal-fired power plants, is being developed and promoted, there are "special" or "exceptional" projects, which due to their circumstances involve use of the new technology. With respect to IGCC, the most obvious examples of such projects are the historic IGCC plants supported by the USDOE funding, i.e., the Wabash River, Tampa Electric and Pinon Pines projects. Because of their special circumstances, these projects do not demonstrate that IGCC technology is generally appropriate and indeed one purpose of these DOE projects was to further develop IGCC technology so that it would be available for privately financed projects.

The other projects pointed to by this comment must be considered such special projects. In particular, the proposed Southern Illinois Clean Energy Center (Steelhead Energy project) northeast of Marion, Illinois, for which an application was submitted to Illinois EPA in November 2004, is readily distinguished from the proposed plant. That proposed power plant would be one-third the size of the proposed plant (500 MW compared to 1500 MW). That source also includes a substitute natural gas plant. This plant affects the energy balance of the project, as it contributes to the electrical output of the source, at the same time that is also consumes electricity, and may provide reserve fuel capacity for the power plant. In addition, that project would be located on an existing natural gas transmission pipeline, which would allow the power plant to continue to generate electricity during outages of the gasification facilities.

In addition, the fact that an application has been submitted does not demonstrate that a proposed plant will be built. The Illinois EPA has received applications for proposed coal-fired power plant projects involving boilers that have not been pursued to permit issuance by the applicant, notably an application from Midwest Generation to install coal-fired boilers at its former Collins plant and an application from the Illinois Energy Group for a new plant near Benton. Moreover, the issuance of a permit does not demonstrate that a proposed plant will be built, particularly as financial arrangements for power plants are not finalized until after the construction permit is issued. Lastly, the construction of a plant may not demonstrate that technology will perform as designed, as shown by the failure of the USDOE financed Pinon Pines IGCC project.

41. Because it is more energy efficient, a plant using IGCC technology would also emit significantly less carbon dioxide (CO_2) than a plant using pulverized coal boiler technology, as proposed. The CO_2 emissions from the proposed plant could be reduced from an estimated 11.5 million tons/yr to an estimated 10.3 million tons/year by using IGCC technology.

Lower CO_2 emissions are one of the benefits hoped for with IGCC technology, both due to the improvements in energy efficiency and potential for sequestration of CO_2. However, significantly lower CO_2 emissions have only been achieved with certain IGCC technology using a solid coal feed, rather than a coal slurry. Sequestration is a further refinement on top of IGCC technology that is still being developed with support by the USDOE. It is important

to remember that at this time CO_2 is not a regulated pollutant. Applicable state or federal standards or requirements have yet to be enacted for CO_2.

42. IGCC should be seriously considered because there is a very high likelihood that regulations addressing CO_2 emissions will be adopted in the near future. Some utility companies already factor future CO_2 regulation into their plans. The prospect of future regulatory costs must be considered to determine the full costs of the options for minimizing emissions of currently regulated pollutants.

The Illinois EPA agrees with the spirit of this comment and encourages all utility companies to consider future regulations for CO_2 in their planning.

43. The control technology being proposed for this plant is not BACT when better technology for power generation, such as IGCC technology, could be used.

For purposes of BACT, a permitting authority does not have the legal right to require that a proposed plant use a technology like IGCC technology, which, while technically feasible, is also still developing, if doing so would mean that the proposed plant could not be built.

44. The proposed plant is not the right place for forcing of IGCC technology.

The Illinois EPA agrees with this comment.

BACT – Alternative Fuels

45. Natural gas should be seriously considered because any new power plant will be in operation for many decades and there is a likelihood that regulations addressing CO_2 emissions will be adopted in the near future. Some utilities already factor CO_2 regulations into their plans. The prospect of future regulatory costs must be considered to determine the full costs of the options for minimizing emissions of currently regulated pollutants. The cost of building a natural gas plant is also significantly lower than a coal-fired plant. This lower construction cost, in turn, offsets the higher fuel price. Even if a natural gas plant is calculated to be more expensive than a coal plant, it still constitutes BACT unless cost and other relevant factors show it is not "achievable."

It is inappropriate to consider a natural gas-fired power plant as an alternative to the proposed coal-fired power plant as suggested by this comment. The Illinois EPA required the requisite top-down BACT analysis by Prairie State. Moreover, the availability of reliable and affordable electrical power, as provided by coal, is a critical factor in the high standard of living enjoyed in Illinois and the United States. Use of coal in power plants, in areas where coal is available, allows natural gas to be available and affordable for heating homes, businesses, and the vast majority of industrial plants. The lower cost of construction for a natural gas plant does not offset the higher fuel cost of natural gas for a base load power plant, like the proposed plant.

46. Prairie State failed to fully evaluate the effectiveness of using low-sulfur coal or a blend of low-sulfur coal and local coal. The Illinois EPA inappropriately eliminated low-sulfur coals on the basis of "scope." Cleaner fuels, including lower sulfur western coals must be evaluated in the BACT analysis; they cannot be eliminated simply because of scope. The widespread use of western coal in Illinois proves that it is "available" in the context of the BACT definition, and it is technically feasible and cost-effective to use.

The project that must be addressed when evaluating BACT is the project for which an application has been submitted, i.e., a proposed mine-mouth power plant. The source of coal for which the plant would be developed is a specific reserve of 240 million tons of recoverable coal, which would meet the needs of the proposed plant for more than 30 years. Accordingly, the use of a particular coal supply is an inherent aspect of the proposed project. To require an evaluation of an alternative coal supply, as suggested by this comment, would constitute a fundamental change to the project.

Prairie State has identified a number of advantages that accrue to the environment from a mine-mouth power plant, including reduced impacts from transportation of coal, as compared to use of another coal supply. The Illinois EPA has broadly considered the use of alternative coal supplies for the proposed plant as suggested by this comment. The Illinois EPA concludes that the impacts of using a non-local coal are excessive if the emissions from the local coal supply can be appropriately controlled. The price and value of western coal has increased substantially in recent years, both as the demand has increased and as the cost of crude oil, which is the source of the diesel fuel used in the trains that transport coal, has risen. The wide-spread use of western low-sulfur coal in Illinois is a consequence of the lack of scrubbers on Illinois' existing coal-fired power plants. It is not directly relevant to the need to evaluate use of alternative fuels for the proposed plant, which would and must be equipped with a high-efficiency scrubber for SO_2. It also does not show that it would be cost-effective to use such coal at the proposed plant.

47. Prairie State must evaluate cleaner fuels including lower sulfur western coals in the BACT analysis. They cannot be eliminated simply because of scope. In Inter-Power of New York, PSD Appeal Nos. 92-8 and 92-9 (EAB March 16, 1994), at 134 states "[I]n deciding what constitutes BACT, the Agency must consider both the cleanliness of the fuel and the use of add-on pollution control devices." Id. (citing Hawaiian Commercial & Sugar Company, PSD Appeal No. 92-1 (EAB July 20, 1992), at 5 n.7. "This requirement applies by virtue of the 1990 Clean Air Act amendments, which "expressly require consideration of clean fuels in selecting BACT," and by virtue of "prior decisions of the Administrator, which state that a proper BACT analysis must include consideration of cleaner forms of the fuel proposed by the source." Id. at 145. This is clearly unlawful. See In re Inter-Power of New York, Inc. 5 EAB 130, 145 (EAB 1994) ("the 1990 Clean Air Act Amendment * * * expressly requires consideration of clean fuels in selecting BACT, as well as prior decisions of the Administrator, which state that a proper BACT analysis must include consideration of cleaner forms of the fuel proposed by the source."). Low sulfur coal is clearly available because it is used in the majority of the coal-fired power plants in Illinois. For the same reason low-sulfur coal is also cost-effective. The BACT (and MACT) analyses must be redone to include consideration of low-sulfur coal, as well as blending Illinois high-sulfur coal with low-sulfur coal in various amounts.

Closer review of these EAB decisions show that they do not address the circumstances presented by the proposed plant. In particular, neither Hawaii or New York have local coal reserves. For the projects in those states, the planned fuel supply for the proposed project was not an intrinsic aspect of the project. Instead, the selection of the planned fuel supply for the proposed plant involved a business decision by the source considering potential fuel supplies, all of which would have to be transported substantial distances to the proposed plant. In addition, the plants were not subject to stringent requirements for SO_2 scrubbing, as set for the proposed plant. A series of EAB cases support the approach being taken to the fuel supply at the proposed plant. These cases support the principle that a permitting authority should consider BACT for the project for which an application has been submitted and not "re-define the source."

In addition, these cases provide no support for the proposition that blends of fuel, i.e., a mix of the mine-mouth coal supply with low-sulfur coal from outside Illinois, as suggested by this comment, must be considered as part of a BACT determination. Consideration of blends of fuels would also not be a straightforward matter, nor does the comment suggest how this evaluation should be performed. Such blends could range from a trace of low-sulfur coal to a trace of mine-mouth coal. Moreover, depending upon how the evaluation were structured, various outcomes are obviously possible. For example, the evaluation could simply confirm the appropriateness of the selected coal supply, as use of that coal is supported and use of any other coal supply results in higher costs. Another possibility is an evaluation in which the use of the more cost-effective fuel supply subsidizes the less cost-effective fuel supply, so that the evaluation calculates an appropriate blend of coal that is the result of the cost value that is established as an acceptable cost for control of emissions, rather than an evaluation of cost-effectiveness of particular combinations of fuels.

48. Of the 62 large coal-fired utility boilers in Illinois, 42 used low-sulfur western coal in 2002. These include many units that were originally designed to burn high-sulfur coal. Many of these plants, including the nearby Baldwin power plant, switched to western coal as recently as 1999. This widespread use of western coal in Illinois proves that it is "available" in the context of the BACT definition and that it is technically feasible and cost-effective to use. The Illinois EPA cannot eliminate this control option simply on the basis of scope.

While the use of western low-sulfur coal at existing power plants generally shows that it is an available fuel, it does not show that its use would be cost-effective at the proposed plant. In this regard, the cost of using western coal at those existing plants reflects a business decision that is, in part, facilitated because such plants are not required to have SO_2 scrubbers by applicable regulations. Moreover, BACT is a case-by-case determination, for which a relevant aspect of the determination is appropriately defining the scope of a project as explained above.

49. Low-sulfur coal would help mitigate three problems facing Prairie State's proposal: SO_2 is a precursor to PM2.5 and the Greater St. Louis area violates that standard, Prairie State's own modeling shows SO_2 NAAQS violations, and SO_2 is the principle threat to the Wilderness Area at the Mingo Wildlife Refuge, both for visibility and acid deposition.

The "problems" alleged by this comment do not exist. Even if the proposed plant were not to be built, the greater St. Louis area would be nonattainment for PM2.5. Implementation of CAIR and other new control measures, such as ultra-low sulfur diesel fuel for vehicles, will move forward to reduce SO_2 emissions both locally and regionally and improve PM2.5 air quality in the St. Louis area. These new control measures, especially CAIR, will also act to further improve visibility in the Mingo Wilderness Area. Finally, the alleged violations of the SO_2 NAAQS by the proposed plant are a result of the methodology used for air quality modeling as it addresses existing sources. More careful review of the modeling results shows that the proposed plant would not cause a violation of SO_2 air quality standards.

50. The BACT analysis failed to identify all of the available control options, as required, because the analysis failed to evaluate IGCC using washed coal.

The use of washed or unwashed coal was not a significant factor in the evaluation of IGCC technology and the rejection of IGCC technology by the Illinois EPA.

51. The MACT analysis must consider low-sulfur coal. Prairie State's MACT analysis failed to consider the possibility of burning low-sulfur coal as a cost-effective method to reduce the emissions of pollutants other than SO_2.

The issue of alternative fuel supplies was addressed in its MACT rulemaking and rejected. In particular, USEPA separately addressed the different ranks of coal in this rulemaking, distinguishing between bituminous, sub-bituminous and lignite fired boilers as separate categories of sources. In this regard, USEPA found that "…the choice of coal ranks to be burned for a given unit is based on economic issues, including availability of coal within the region or locale." A number of coal-fired units, including all known lignite–fired units, are "mine-mouth" (or near mine-mouth) operations (i.e., the unit is constructed on or near the coal mine itself with coal transport often being by conveyor directly from the mine) and many do not have the infrastructure in place (e.g., interstate rail lines to import other ranks of coal to replace all lignite coal combusted). The EPA also found that substitution of coal rank, in most cases, would require significant modification or retooling of a unit, which would indicate a pertinent difference in the design/operation of the units.

52. Prairie State's analysis does not reflect BACT it failed to consider fuels like natural gas or low-sulfur coal, which would lessen the plant's impacts on air quality.

The Illinois EPA required the requisite top-down BACT analysis by Prairie State. The availability of reliable and affordable electrical power, as provided by coal, is a critical factor in the high standard of living enjoyed in Illinois and the United States. The development of a mine-mouth power plant is an intrinsic aspect of the proposed plant, which would be developed to use a specific reserve of fuel, which is adequate for the expected life of the plant. Because of the selection of fuel, the air emission control equipment for the proposed plant must be designed to handle emissions from combustion of unwashed high sulfur, high ash coal and be very efficient, including a wet scrubbing system that must be operated to achieve an SO_2 removal efficiency of at least 98 percent.

53. Even though the proposed plant would be developed as a mine-mouth power plant, it should be allowed to use Illinois No. 5 or No. 6 coal, similar to the design fuel for the plant, from other mines. This ability is important to accommodate events that might occur with the mine-mouth coal supply during the many years during which the proposed plant would be operating.

It is appropriate to allow the proposed plant to have an alternative source of fuel, as generally requested by this comment, to accommodate potential interruptions in the mine-mouth coal supply. At the same time, this request is not accompanied by adequate justification to allow this alternative or "standby" supply of fuel for the proposed plant to be unwashed coal. This is because the decision allowing use of unwashed coal by the plant reflected a case-by-case determination for the mine-mouth fuel supply for the plant, as discussed below. This determination is not generally transferable to other mines whose circumstances and location would be different, so that the impacts accompanying washing of the mine-mouth coal supply would not necessarily be present with those other coal supplies. Accordingly, the alternative source of coal requested by this comment is provided but restricted to washed coal.

BACT – Coal Washing

54. Prairie State is not using BACT because it is not using coal washing. The permit should require coal washing because pulverized coal boilers with scrubbers and suitable coal preparation are BACT for this project. Coal washing will not have costs or impacts that offset the benefits as alleged in Finding 1(b) of the draft permit.

Coal washing has been considered as an option to further control emissions from the coal-fired boilers at the proposed plant. Coal washing does not achieve the required level of emissions control to allow it to stand in place of the add-on control devices that must be used on the boilers. The theoretical benefits of coal washing as a supplemental technique with the necessary add-on control devices are outweighed by the cost, energy and environmental impacts of coal washing. As a general matter, coal washing would control the readily controlled emissions, which the add-on control devices would also easily control. Coal washing would do little to achieve the overall control of emissions that is required and can only be achieved with modern high-efficiency add-on control devices.

55. The application rejects coal washing as part of BACT due to energy, environmental and economic impacts associated with coal washing. In its project summary accompanying the draft permit, the Illinois EPA discusses coal washing as a part of the BACT determination. However, the reasoning used in the third paragraph of page 8, "Coal washing becomes economical when coal is transported over distance. Then the savings in transportation costs for the washed coal, which contains 15 to 20 percent more heating value per ton, offsets the costs associated with coal washing.", is not sufficient by itself to eliminate a requirement for coal washing. The technical feasibility of coal washing has been demonstrated by existing coal-fired power plants utilizing washed coal, including some using coal washing in combination with wet scrubbing. The record needs to thoroughly and conclusively justify

any decision to not require coal washing, as coal washing is commonly seen as a beneficial process for control of emissions.

The Illinois EPA has carefully considered and ultimately rejected coal washing as a possible measure that could also be used at the proposed plant to further control emissions. This is documented in the record and in the responses to the public comments supporting coal washing, which follow. Incidentally, transportation costs were not a factor in this evaluation. The statement in the project summary with respect to transportation costs, as mentioned by this comment, was an attempt to identify for the public one of the simpler factors that may contribute to an existing power plant using washed coal. It is not the only factor in such decisions. It is also not relevant to the proposed new plant as it would be a mine-mouth plant.

56. The proposed plant should be required to use coal-washing as BACT. Prairie State's arguments against coal-washing for the proposed plant are of great concern. My analysis show that coal-washing reduces sulfur emissions by an additional 36% and in combination with a scrubber would reduce mercury emissions by 90%, all at a negative cost. Prairie State incorrectly calculates the sulfur reductions; and according to my calculations greatly overestimates the costs of the wash plant. Some of their mathematical errors in their evaluation are off by several orders of magnitude.

The analysis accompanying these comments cannot be relied upon as it suggests that coal washing can be accomplished with negative cost, that is, for free. Coal washing has costs. At a minimum, it entails costs for construction and operation of a coal washing facility. To conclude that coal washing has a negative cost, an analysis must assume monetary benefits from coal washing that offset the various costs associated with coal washing. However, Prairie State has considered such benefits, as coal-washing would lower the capital and operating costs of the plant as the boilers would not have to be as capable of handling as much rock and ash material as present in raw coal. It is inappropriate to place higher credence on the estimates of these savings as provided in comments, as it is in Prairie State's self-interest to accurately assess the potential operational benefits from the use of coal washing.

57. Coal washing should be required. The absence of coal washing will result in elevated emissions of PM, SO_2, and mercury. While ongoing research continues to clarify the mechanisms by which fine particulate affects health, elevated levels of PM10 have been associated with important health effects. SO_2 is a well-established respiratory irritant that can increase the frequency and severity of asthma attacks, among other respiratory effects. PM and SO_2 would have the greatest impacts on the communities closest to the proposed plant. By contrast, mercury is a hazard as it gradually settles from the air and is incorporated into the aquatic food chain. Mercury emissions would significantly contribute to adverse health effects throughout the state and the Midwest. The major target is the developing nervous system of the fetus when a pregnant woman eats mercury-contaminated fish.

The proposed plant does not pose a risk for elevated levels of pollutants in the surrounding communities. In particular, the absence of coal washing will not result in elevated levels of emissions from the proposed plant as the plant must be equipped and operated with add-on

control devices to effectively control emissions.

58. Coal washing should be required for the proposed plant to continue progress in Illinois in reducing environmental mercury contamination.

Coal washing is not needed to address mercury emissions as it would not eliminate or substitute for effective control of mercury emissions from the boilers. The information on the effectiveness of coal-washing as a means to reduce mercury emissions, as applied to Illinois coal, is that it would only provide at most a 50 percent reduction in the mercury content of the coal. In contrast, the add-on control measures applied to the boilers are expected to provide more than 90 percent overall control of the mercury emissions, a level which the Illinois EPA considers more appropriate for control of mercury emissions from power plants.

59. Many mine mouth facilities use coal washing, including Cash Creek Generation's proposed plant in Louisville, Kentucky.

This observation is not a sufficient basis to require use of coal washing at the proposed plant. The relevant question is whether coal washing should be required at the proposed plant as part of BACT based on the impacts that would occur for Illinois and the proposed project.

Beyond this, some plants wash coal; others, such as the proposed Longview plant in West Virginia, do not. In the case of Cash Creek's proposed plant in Kentucky, the SO_2 BACT limit proposed in its application with its washed coal supply was 0.187 lb SO_2/mmBtu. This limit was higher than the SO_2 limit being set as BACT for the proposed plant. It is also arguable whether Cash Creek should even be considered a mine-mouth plant, as it would obtain coal from existing mine(s). Incidentally, this application was withdrawn and Cash Creek is now engaged in "pre-application" discussions with the State of Kentucky for resubmittal of an application. While Cash Creek may have indicated that it will be submitting a new application that proposes a limit a limit of 0.12 lb SO_2/mmBtu, 3-hour average, (based on 98.3 percent overall removal), it is inappropriate to place any credence on this information. This is because this information is not yet part of an application. Even when an application is submitted, the project would be years away from being permitted, so that it should not be directly compared to the proposed plant.

60. Coal washing was improperly eliminated in the BACT analysis because it was only evaluated as a method to reduce SO_2 emissions. The analysis focuses on the negative aspects of coal washing, without considering the positive aspects. Coal washing was eliminated for several reasons: (1) requires significant amounts of water; (2) generates two waste streams, gob and slurry; (3) results in significant energy losses; (4) requires the mining of more coal and associated emissions; (5) involves significant capital and operating costs. However, these are not valid reasons for eliminating coal washing. Coal washing, in combination with the balance of the pollution control train, should be evaluated as BACT for PM/PM10 and sulfuric acid mist. It should also be evaluated as MACT due to its ability to remove trace metals.

Coal washing was appropriately evaluated. Significant reductions in emissions of pollutants

other than SO_2 cannot be demonstrated to occur or reasonably be assumed to occur with coal washing if it were to be applied to the proposed plant. This is because the proposed plant would be equipped with add-on control devices to directly control the emissions of other pollutants. In contrast, coal washing can be critical as applied to existing boilers that are equipped with particulate matter control devices with limited capability or are not equipped with scrubbers. Even for the proposed plant, engineering judgments differ on whether the reduction in sulfur content of the coal achieved with washing, will have any effect on SO_2 emissions given the level of control required of the scrubbers.

61. In order to eliminate use of coal washing for the proposed plant, Prairie State must demonstrate that "unusual circumstances" apply to the proposed plant. This is because about 80% of the coal that is burned in the eastern US. is washed, including large amounts of Illinois No. 6. Further, coal-fired power plants that have recently been permitted or that are currently going through PSD review, are proposing to use washed coal. The recently permitted Elm Road plant, in Wisconsin will use a washed Appalachian Pittsburgh No. 8 coal, similar to the Illinois No. 6. It is not believable that coal washing would not be technically and economically feasible for the proposed plant, absent the demonstration of unique circumstances. When a technology is widely used, such as coal washing, the determination that it is not BACT involves a "demonstration that circumstances exist at the source which distinguish it from other sources where the control technology may have been required previously."

USEPA guidance is not clear that "unusual circumstances" must be shown to eliminate the use of coal washing at the proposed plant from consideration. This is because it is a situation where emissions would be effectively controlled by the add-on control technology, which is required irrespective of whether the coal is washed. The need for "unusual circumstances" to be shown as part of the BACT determination is more appropriate when something other than the most effective control option for BACT has been selected.

However, "unusual circumstances" can be shown for the proposed plant, including the required control devices (very high efficiency scrubber and wet ESP), new requirements that apply to wastewater from coal washing facilities, and increased concern over and sensitivity to the risks posed to the environment from wastewater and solid waste associated with coal washing facilities.

62. It is not reasonable to eliminate coal washing for the proposed plant based on cost. "[W]here a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review." (NSR Manual, p. B.31). The applicant and Illinois EPA have not documented any significant cost differences between coal washing for the proposed plant and coal washing for any other coal-fired power plant where it is currently used or proposed to be used, such as Cash creek Generation.

This observation is not a sufficient basis to require use of coal washing at the proposed plant. The relevant question is whether coal washing should be required at the proposed plant as

part of BACT based on the impacts that would occur for Illinois and the proposed project. An applicant is not required to evaluate the impacts that occur at other plants that have elected to use a particular control technology. In the case of Cash Creek's proposed plant in Kentucky, the actual SO_2 limit originally proposed as BACT with washed coal, as referred to by this comment, was 0.187 lb/mmBtu. This is higher than the lb/mmBtu SO_2 limit being established as BACT for the proposed plant.

63. The impacts used to eliminate coal washing, e.g., water use, waste streams, etc., are present at all coal washing facilities. These impacts only become important if sensitive site-specific receptors exist or when the incremental emissions reduction potential of the top control is only marginally greater than the next most effective option. "However, the fact that a control device creates liquid and solid waste does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications." (NSR Manual, p. B.47.)

This comment cites general guidance from USEPA for add-on control devices. Coal washing is a pre-combustion fuel treatment process. For coal washing, the circumstances are not as simple as suggested by this comment. In light of continuing scrutiny, coal-washing cannot be considered a benign process from an environmental perspective. Because of the presence of high-efficiency add-on controls, the proposed plant has the ability to avoid the environmental impacts associated with a coal washing facility. In addition, the circumstances are not similar to those at existing coal-washing facilities as coal washing for the proposed plant would create new coal waste disposal sites or require closed disposal sites to be reopened.

64. The BACT analysis evaluated coal washing in isolation, only for SO_2. However, coal washing removes not only sulfur, which becomes SO_2 and sulfuric acid mist, but also ash, which becomes PM/PM10, and metals, which would otherwise be emitted at the stack. Coal washing should have been evaluated in combination with other, downstream pollution control systems that remove these other pollutants. The NSR Manual notes that "combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative, particularly if the "top" alternative is eliminated." Similarly, the NSR Manual notes that "[c]ombinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add on controls are likely to yield more effective means of emissions control than either approach alone…" When a control technology reduces several pollutants, it is standard practice to sum the reductions and use the sum to calculate cost-effectiveness. It is also standard practice to consider the reductions of non-PSD pollutants as benefits in the environmental impacts analysis. Thus, coal washing should have been evaluated in combination with other methods that remove SO_2, sulfuric acid mist, PM/PM10, and metals.

Given the level of control for pollutants other than SO_2 emitted from the coal-fired boilers, which is required independent of the use of coal washing, significant reductions in emissions of these other pollutants cannot be assumed to result from the use of coal washing.

65. Coal washing has benefits for control of other pollutants besides SO_2, as it also significantly decreases ash and trace metals in the coal, reducing PM and trace metal emissions. Studies indicate coal washing for Illinois No. 6 coals when reported on a lb/mmBtu basis reduces the ash content by 87%, sulfur by 30%, beryllium by 52%, mercury by 60%, lead by 54%, and manganese by up to 95%. (Fonseca, "Challenges of Coal Preparation," *Mining Engineering*, September, 1995)

The information referenced in this comment does not demonstrate reductions in <u>emissions</u> of other pollutants would occur with coal washing, only reductions of contaminant levels in the raw coal. Moreover, the specific data cannot be relied upon as generally representing the results of coal washing for Illinois coal. The data addresses cleaning of a high ash, very low sulfur Illinois coal from a single mine, with the raw coal containing 32 percent ash, 0.73 percent sulfur, and about 0.13 ppm mercury. Elsewhere in the article, the author acknowledges variability in the removal of trace metals from coal achieved with washing. Of particular concern is the removal achieved for mercury by coal washing, which based on data from Pittsburgh coals, can range from 10 to 50 percent. In such circumstances, the necessary levels of emission control can only be achieved by add-on control equipment.

As a general matter, the referenced article was prepared during the first year of the federal Acid Rain Program. At that time, operators of coal-fired power plants had to decide how to most economically reduce SO_2 emissions to comply with that program. The author finds that coal cleaning is a cost-effective means to obtain some reductions in SO_2 emissions from an uncontrolled coal-fired boiler. However, installation of a scrubber is more cost-effective than using "advanced coal cleaning" techniques to obtain a deep reduction in SO_2 emissions.

66. Prairie State argues that coal washing would increase the amount of coal to be mined by 1.3 million tons per year, or about 20%, resulting in the loss of about 95 MW of electrical output. No support is provided for these estimates. Coal washing increases the Btu content of the feed coal, which means that less coal would be required to generate the same amount of electricity. This estimate should be supported, or this argument dropped. Regardless, this would be true only if the coal waste is disposed of and not reclaimed. Fluidized bed boilers are widely used to recover the energy value in coal wastes as electricity. A small fluidized bed boiler could be added to the plant to recover the energy value of gob, reducing the size of the two main boilers.

It is unquestioned that coal washing is not a perfect process and removes coal from the fuel stream, as well as rock and pyritic minerals. Coal washing is accompanied by a substantial loss of coal material with the coal waste. (Otherwise, how would coal waste have the energy value to be used as fuel in power plants that are specifically developed to burn coal waste.) Additional coal (energy) must be mined to make up for the coal that is lost with the waste. The amount of coal lost in washing, which must be made up by mining more coal, is also related to the type and level of washing that is conducted. The estimate provided by Prairie State for the amount of coal that would be lost to the waste with washing to different levels of sulfur removal is adequately supported. The overall analysis has also been properly conducted as it is based on the amount of energy (Btu) that is required for the boilers, not the amount of coal, which does vary depending upon whether raw or washed coal is fired.

The particular loss of energy cited in this comment, i.e., 95 MW, was not a key factor in the evaluation of coal washing and appears to be an expression of the amount of electricity that the "lost coal" could have generated. At the same time, it must be recognized that coal mining and coal washing do consume energy that are part of the internal energy costs of generating electricity. These energy costs only loose importance if they are accompanied by equivalent energy savings elsewhere in the power generation process.

Incidentally, as the energy in coal waste could be recovered, as mentioned by the comment, this is effectively what the proposed plant would do as a mine mouth plant. However, it would do so without first processing the coal and creating coal waste (avoiding the impacts of coal washing) and then having to construct and operate a third boiler. In addition, it would do so without uncertainty about the future fate of the coal waste, as the Illinois EPA cannot prohibit the disposal of coal waste and require the plant to continue operating this third boiler. As such, the proposed plant would do exactly what the comment suggests, that is, reclaims coal waste by simply avoiding creation of coal waste, with the environmental concerns that it poses.

67. Prairie State argues that coal washing would annually generate about 2.6 million tons of gob (solid waste) and about 27 million gallons coal waste slurry. These types of wastes are produced by all coal washing facilities, so are not a reasonable basis to eliminate coal washing. Further, the BACT analysis fails to mention that the net increase in waste would probably be very small because the material present in the slurry and gob would otherwise be present in the ash and scrubber byproducts, which would also have to be disposed of. Therefore, there should be no significant net increase in the quantity of waste products or landfill and impoundment requirements. The waste analysis should estimate the net change in residuals, considering reductions in those from the air pollution control train.

Prairie State did account for the net change in solid waste streams from the proposed plant with and without coal washing. This comment is certainly correct that some of the waste material generated from coal washing would be offset by a reduction in the amount of combustion waste from the boiler, as there would be less rock and ash in the coal going into the boilers. Overall, however, more waste is created with coal washing as substantially more raw coal must be mined, to replace the coal that is lost in gob and coal slurry from the coal washing facility. In addition, a different type of waste is created by coal washing, as the gob contains coal, pyritic sulfur and free water in addition to inert rock. The coal slurry exists as a liquid, a form of waste not even present with the combustion waste. Accordingly, coal washing waste must be managed differently than the coal combustion waste, which is present only in a solid form and is stabilized by gypsum and unreacted limestone.

Finally, environmental concerns are not static and evolve as society becomes more aware of the risks to which it is subjecting itself. The fact that a certain practice was deemed environmentally acceptable in the past does not demonstrate that the practice should continue to be considered acceptable or innocuous and not subjected to closer scrutiny and care. In this regard, environmental groups are concerned not only about the emissions from coal-fired power plants, but also the environmental impacts from mining, washing and transporting

coal, e.g., *Cradle To Grave: The Environmental Impacts from Coal*, Clean Air Task Force, 2001.

68. The BACT analysis argues that coal washing would increase emissions, from mining more coal and using a thermal dryer to dry the washed coal. Similar effects occur at other coal washing facilities, so are not a reasonable basis to eliminate coal washing. Also, the BACT analysis failed to mention that coal washing would reduce emissions from the mining and handling of limestone for the SO_2 scrubbers. The analysis should either drop this argument or document the net change in emissions.

These incidental observations made by Prairie State in the application were not relied upon by the Illinois EPA in its evaluation of coal washing. Also, drying of washed coal is an additional step in coal preparation that would not be needed for a mine-mouth plant.

69. The BACT analysis argues that because the proposed plant is a mine-mouth plant, it would not enjoy any of the benefits associated with reduced transportation costs. Prairie State would not incur any transportation costs because it is a mine-mouth plant. Therefore, arguing that it would forgo a reduction in those costs is irrelevant.

The statement made by Prairie State in the application to which this comment objects is correct, i.e., "…[the facility] would not enjoy any of the benefits normally associated with the reduced transportation costs typically associated with coal washing." However, the Illinois EPA does not consider this statement part of Prairie State's analytical BACT evaluation, in part, because there is not a clear role that such savings could play in the analysis. Rather, this statement is viewed as general commentary on the difference in the circumstances of the proposed plant and those of many other power plants that are using washed coal.

70. Instead of providing a balanced discussion of the benefits of coal washing, the application focuses only on transportation-related benefits of coal washing. Since this plant is proposed to be mine-mouth facility, there are no transportation benefits. As a result, the application comes to the false conclusion that coal washing is a cost, not a savings.

This is not correct. Prairie State's cost analysis for coal washing focused on the actual costs of coal washing. It did not focus on theoretical costs for transporting coal, which are not generally relevant for a mine-mouth plant.

71. Prairie State's BACT analysis concluded that the incremental cost of using coal washing at the proposed plant would be "…over 1200 times more than the cost of using the proposed add-on or post-combustion measures." However, the cost-effectiveness analysis deviates substantially from the procedures outlined in the NSR Manual and is invalid.

Prairie State's conclusion, as quoted in this comment, does not reflect a flaw in Prairie State's evaluation of the costs of coal washing. Rather, it is a result of Prairie State's judgment about the effectiveness of coal washing in providing additional reductions in SO_2 emissions. Prairie State expects that coal washing will at most provide a very small additional reduction in SO_2 emissions, given the high efficiency of the scrubbers. In other words, the primary effect of coal washing on SO_2 emissions would be to control emissions that would otherwise be

controlled by the scrubbers. This is not an unreasonable position given the overall level of removal efficiency of SO_2 that is required as BACT. If a greater reduction in SO_2 would occur, the cost-effectiveness would be better, but still far higher than the cost-effectiveness of the scrubbers by themselves.

72. The basis of the cost estimate for coal washing was not documented. The capital and operating cost of coal washing are presented without support. The BACT analysis contains none of the information required to evaluate the estimated costs – design parameters, battery limits, equipment costs, or support for cost estimates. The size of the coal washing plant, in tons processed per year, for example, is not revealed. Thus, it is impossible for the public to review the analysis. The *sine qua non* of a cost effectiveness analysis for BACT is the design basis of the process being costed. "Before costs can be estimated, the control system design parameters must be specified... In general, the BACT analysis should present vendor-supplied design parameters." "The basis for equipment cost estimates also should be documented." (NSR Manual, p. B.32, 33.) The EAB has upheld this interpretation, remanding PSD permits because the agency's "cost-effectiveness analysis was incomplete." "On remand, … is directed to perform a complete analysis of SCR's cost-effectiveness, including comparisons of costs to other facilities and to other technologies, document its findings, submit those findings to public review…" *In re Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4, 5 (EAB, June 22, 2000).

Prairie State provided adequate documentation for its cost estimates for coal washing. It also provided documentation for the key design parameters that determine the costs associated with coal washing. This is the "washability" of the local coal supply, which dictates the size of the washing facility and the quantity of waste produced by coal washing. While Prairie State could have presented this information in a manner that was better documented or could be more readily understood, this does not indicate that the basis for the cost estimates were not adequately documented. In addition, there is ample information on costs of coal washing in light of the various comments on the subject of coal washing. As a general matter, this body of information either supports Prairie State's estimates or would result in minor changes to the cost estimates that would not alter the conclusion of the evaluation.

73. Reliance on an incremental cost analysis was improper. The BACT analysis presents a calculation of incremental cost. However, it is inappropriate to consider only an incremental cost analysis, even if it were done properly (which it was not, as discussed in other comment). Further, the applicant used this tool to evaluate combinations of technologies, which is inconsistent with the purpose of an incremental analysis.

The analysis of coal-washing was properly conducted, as coal-washing is an inferior control technology. That is, coal washing can only be reasonably evaluated in combination with scrubbers, since coal washing, by itself, is not able to comply with applicable requirements for SO_2. In this regard, pursuant to the federal NSPS, at least 90 percent of the SO_2 emissions from the coal-fired boilers must be controlled. Given the size of the proposed plant, the SO_2 scrubbers will nominally control approximately 600,000 tons of SO_2 emissions. Accordingly, the evaluation of cost-effectiveness for the combination of scrubbing and coal washing must be conducted in a way that is consistent with general economic principles to realistically portray

the cost impacts of using coal-washing as a supplemental technique with scrubbing. Use of total or average costs yields a value for cost-effectiveness that, in this context, does not provide an appropriate evaluation of the true cost impacts of coal washing. This is because it is distorted by the magnitude of the costs for scrubbing and the amount of SO_2 emissions controlled by scrubbing. In addition, any benefits from coal washing have been further minimized by the setting of the 98 percent control efficiency requirement for the scrubber.

74. The NSR Manual states "for control alternatives that have been effectively employed in the same source category, the economic impact of such alternatives on the particular source under review should be not nearly as pertinent to the BACT decision making process as the average and, where appropriate, incremental cost effectiveness of the control alternative." (NSR Manual, p. B.31.) Here, the applicant has only presented an incremental cost analysis and has placed a heavy emphasis on it, concluding that "economic costs are unacceptable."

The analysis of coal-washing that has been conducted is appropriate. This comment cites general guidance developed by USEPA for BACT determinations that is not directly applicable to the circumstances of the proposed plant. It would be relevant if SO_2 scrubbing were being eliminated, because SO_2 scrubbing is the control alternative that is effectively employed on all new coal-fired power plants. However, coal washing is a supplementary control technique that can only be used in combination with scrubbing. It is appropriate to focus on the incremental cost-effectiveness of coal washing, as coal washing would provide at most an incremental reduction in emissions. This is necessary to evaluate the true impacts of this combination of control measures. As a general matter, it is also necessary to allow the continued development of better alternatives for control of emissions, which meet environmental standards with reduced costs and other impacts compared to the control technologies that were previously available.

If the cost-effectiveness evaluation were to focus on the average cost-effectiveness of the combination of control measures, these considerations would not be adequately portrayed. This is because scrubbing is a highly effective control technology for the proposed plant, in large part because of the magnitude of SO_2 emissions that it would control. As a result, a cost-effectiveness evaluation based on average costs could "absorb" the costs of coal washing, even if it achieved no additional reductions in SO_2 emissions.In addition, a cost-effectiveness evaluation based on average cost could suggest that coal washing would be appropriate for the proposed plant even if the annual costs of coal washing were greater than the total capital cost of the plant. As an average cost-effectiveness evaluation would yield such extreme results, it cannot be relied to evaluate the possible use of coal washing at the proposed plant.

75. Incremental cost effectiveness is never used alone to eliminate an option. It is used in conjunction with average cost effectiveness, and then, only under certain very limited circumstances. The average cost effectiveness, based on the applicant's costs, is about \$220/ton. This is at the lower end of the range for washing Illinois No. 6 coal, or \$117/ton to \$2193/ton. It is also well within the range of the cost of SO_2 removal by other control technologies. Therefore, coal washing is cost effective within the meaning of BACT. The incremental cost effectiveness is only considered "in addition to the average cost effectiveness," not alone, as here.

Incremental cost effectiveness is only used to evaluate differences in cost between "dominant" control technologies. (NSR Manual, p. B.41.) It is not used to evaluate the incremental cost of using multiple controls to meet an emission limit, as advocated in the application. Further, even assuming that coal washing were a "dominant" technology, which it is not, incremental costs among dominant alternatives cannot be used by itself, as done here, to argue one dominant alternative is preferred to another. (NSR Manual, pp. B.43/44.) Therefore, Illinois EPA should reject the applicant's incremental cost effectiveness analysis and base it's BACT determination on the average cost effectiveness.

This comment is based on an erroneous calculation for the effect of coal washing, as it fails to properly calculate the additional reduction in SO_2 emissions that occur from coal washing. In particular, it assumes that coal washing would eliminate 176,000 tons of SO_2 emissions, a value that is over ten times the permitted emissions of the proposed plant with SO_2 scrubbing. This is a reasonable estimate of the amount of equivalent <u>uncontrolled</u> SO_2 emissions that might be removed from the coal supply if coal washing were used or the amount of emissions that might be controlled if there were no scrubbers. However, it is not the reduction in SO_2 emissions that would result from supplementing scrubbing with coal washing, which should be calculated starting from the SO_2 emissions with only scrubbing. Moreover, the NSR Manual does not contain guidance that suggests that the evaluation of a combination of control technologies should be conducted in the manner suggested by this comment.

76. Net costs were not evaluated. The incremental cost analysis itself is not consistent with the procedures recommended in USEPA's Cost Manual or preparing BACT cost effectiveness analyses and omits many factors that would improve the cost-effectiveness of coal washing.

A proper cost analysis for the combination of scrubbing and coal washing was conducted, in a manner that is consistent with the principles contained in guidance on this subject set forth by USEPA, including the NSR Manual. This includes the principle that a cost-evaluation must address both costs and savings associated with different control alternatives.

77. The BACT analysis did not consider the reduction in capital and operating costs of the boiler itself and downstream pollution control equipment and handling of resulting waste products if a washed, rather than a raw coal were fired. The reduction in capital and operating costs from using a washed coal with lower sulfur and ash can be substantial. TVA, for example, has reported a direct correlation between coal ash content and boiler tube failure rate as well as mineral content (ash and sulfur) of coal and power plant cost effects in dollar per ton of coal for several components. Generally, the cost of ash disposal, coal transportation, power plant maintenance, reduction in peaking capacity, reduction in rated capacity, and reduction in plant availability increase as the ash and sulfur content increase. (Ex. 24: Phillips and Cole 1980)

Prairie State's analysis of coal washing did account for and address these benefits for the boilers that would accompany coal washing. For this purpose, an article that is over 20 years old, addressing boilers that may not have been originally designed for raw coal and certainly do not reflect modern boiler design cannot be considered an appropriate basis to estimate

those costs. Incidentally, the cited article also notes transportation costs as another important factor in decisions to use washed coal.

78. The capital and operating cost of SCR depends on the sulfur, ash, and trace element content of the coal. Generally, the higher the concentration of all of these, the higher the capital investment and operating cost for the SCR. Arsenic, for example, deactivates the SCR catalyst. If high concentrations are present in the feed coal, the catalyst volume to achieve a given NOx level would increase. Coal washing removes sulfur and ash, including arsenic.

The loading of ash to an SCR has a minor effect on its cost, as SCRs must generally be designed to allow or facilitate passage of flyash through the SCR. While additional ash loading may require certain design accommodations, it does not create new issues that are not present in the basic operation of an SCR.

79. The capital and operating costs of the ESP depend upon the inlet loading of particulate. Most of the ash in coal is released from the boiler as fly ash or particulate, which is primarily removed in the downstream ESPs, although some is also removed in the wet ESP. Washing of the coal supply would reduce the inlet loading to the ESP and its costs.

The cost of an ESP is not a linear function of dust loading, as most of the flyash is readily collected in the first section of an ESP. The costs of an ESP are driven by the volume of exhaust that must be handled and the final emission limit that must be met. Ash loading is a more significant factor as it affects the size of the associated ash handling and storage systems but these are secondary elements in the cost of an ESP.

80. The capital and operating costs of the SO_2 scrubbers depend upon the amount of sulfur in the coal. The application indicates that coal washing would reduce about 20% of the sulfur. This would reduce the inlet SO_2 to the scrubber and the inlet SO_3 to the wet ESP by a comparable amount, which would proportionately reduce the capital and operating costs of these control devices. (Ex. 17: Srivastava and Jozewicz 2001.)

The reduced loading of sulfur would certainly lower the costs for limestone/lime used in the scrubbers and wet ESPs. It would not significantly affect the capital costs for these devices as such costs are driven by the volume of exhaust that must be handled and the final emission limit that must be met. It would only significantly reduce operating costs other than reagent consumption if these control devices did not have to operate as efficiently, that is, with at most minimal additional reduction in SO_2 and SO_3 emissions. However, the presumption of comments supporting coal washing is that the scrubbers would achieve almost the same efficiency on top of the reduction already achieved in sulfur with coal washing. In such case, the control devices would be working just as hard or harder to extract SO_2 and SO_3 from the flue gases.

81. Incorrect emissions were used in the cost analysis. The incremental cost effectiveness analysis assumes that the SO_2 scrubber and wet ESP would together remove 99.55% of the SO_2, based on the emissions data presented in Tables 2.3-1 and J.6-2 (590,650/593,327) and that coal washing would remove about 20% of the balance of the SO_2 not otherwise

removed by the scrubber and wet ESP. There are several problems with this calculation. Most significantly, the proposed BACT SO_2 limit is based on 98% control, not 99.5% control. If the applicant's cost analysis were corrected to use 98% control, the incremental cost effectiveness, using the applicant's flawed process, would drop from $72,425 to $16,479/ton, which is an acceptable value for incremental cost effectiveness.

The Illinois EPA agrees that Prairie State's approach to the reduction in SO_2 emissions that would result from coal washing, while reasonable, is not the only approach that could be made. However, even with other reasonable approaches to calculating the amount of reduction, the cost-effectiveness of scrubbing with coal washing is excessive. In this regard, the range of cost-effectiveness considered reasonable for control of a pollutant differs from pollutant to pollutant. The cost-effectiveness calculated in this comment, $16,479/ton, is still well above the level considered reasonable for emissions of SO_2. In addition, coal washing was also eliminated as a supplementary coal measure for the proposed plant because of associated environmental and energy impacts unrelated to its costs.

82. Assuming that coal washing would only remove the SO_2 remaining after the wet FGD and wet ESP is inconsistent with the sequence in which the technologies would actually be applied. Coal washing is used to wash the feed coal, before it enters the boiler. Therefore, coal washing would be the first step in the SO_2 removal train and thus would remove 20% of 593,327 ton/yr of SO_2, or 118,665 ton/yr of SO_2. The wet FGD and wet ESP would remove 98% of the balance of the SO_2, or 465,168 ton/yr. The combined removal efficiency would be 98.4%. The incremental cost effectiveness in this case would be $11/ton, which is clearly cost effective.

The cost analysis for coal washing was performed in a proper manner, as the appropriate sequence for the evaluation is determined not by physical or chronological sequence but by regulatory requirements. SO_2 scrubbers must be installed on the coal fired boilers to meet minimum requirements of the federal NSPS that apply to the boilers, i.e., at least 90 percent control of SO_2 emissions. Since coal washing cannot meet this requirement by itself, coal washing is a supplementary control measure for purposes of cost evaluation. In other words, the proposed plant is able to comply with applicable requirements for SO_2 emissions with just scrubbing, it cannot comply with those requirements with just coal washing. Coal washing can only be used at the plant in combination with scrubbing.

83. Coal washing does not result in an adverse economic impact. Considering coal washing to occur first, as discussed in my other comment, based on the applicant's estimate of annualized costs, the average cost-effectiveness of coal washing is $220/ton and the incremental cost is only $11/ton. These costs are well within the range of those borne by others using washed coal. BACT is primarily a technology-based standard. If the cost of control with the top control alternative, expressed in dollars per ton, "is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT." (NSR Manual, p. B.44.) Therefore, coal washing should not be eliminated based on cost.

As explained in the above response, the sequence of control measures used by this commenter for evaluating coal washing is not appropriate. Moreover, the comment confirms that the combination of scrubbing and coal washing at the proposed plant would not be cost-effective. Considering coal washing to occur "first," the cost-effectiveness of coal washing calculated by the commenter is $220/ton of SO_2 controlled. However, this ignores the fact that SO_2 emissions would be controlled by 98 percent by the scrubbers, even if the coal supply were not washed. In other words, for each 100 tons of SO_2 presented by the coal going into the boilers, at most only two tons of SO_2 would be emitted after the scrubbers, a ratio of 1:50. Accordingly, instead of coal washing directly controlling one ton of SO_2 emissions per ton of equivalent SO_2 removed from the raw coal supply, the effect of supplementing scrubbing with coal washing at the proposed plant is to remove at most an additional 1/50th ton of actual SO_2 emissions. This correction increases the cost-effectiveness of supplementary coal washing calculated by the commenter to $11,000/ton ($220 x 50 = $11,000), which is excessive. One indicator of the excessive nature of this cost is that it is 50 times the cost-effectiveness of coal washing for power plants that just use washed coal, without any scrubbing. While coal washing is clearly effective for control of SO_2 emissions for the existing power plant that is not equipped with scrubbers, the cost-effectiveness of coal washing shifts for new plants that must be equipped with very effective SO_2 scrubbers. In this regard, when discussing the merits of coal washing as a means to reduce SO_2 emissions from a power plant, Anthony Fonseca indicates that "…buying SO_2 credits, fuel switching or the installation of FGD would be more effective than using 'advanced coal-cleaning' techniques." (Anthony Fonseca, "Challenges of Coal Preparation," *Mining Engineering*, September 1995).

84. To reduce mercury emissions, the permit should require coal washing. The draft permit is in error in its claim (Finding b) that "for the proposed mine-mouth plant, any benefits would be outweighed by the adverse environmental and economic impacts associated with the washing facility and storage of associated waste." Reliable benefit-cost analysis of coal washing that includes consideration of all relevant costs and benefits (especially public-health benefits of reducing emissions such as mercury; economic benefits to the utility from coal washing; and benefits of reducing impairments of ecosystems) does not support this conclusion. Indeed no full benefit-cost analysis was done. Disproportionate effects on children's health specifically need to be included in the benefit-cost analysis. Because of the failure to include all relevant costs and benefits, including these, and to quantify them according to the best available economic science, the Illinois EPA's claim is false.

Mercury emissions from the proposed coal-fired boilers will be effectively controlled by the add-on control devices on the boilers, which will control mercury emissions to a degree that is far above that possible with coal washing. On a local and regional level, any significant reduction in mercury contamination in the environment will require control of mercury emissions from power plants on a national basis. USEPA has recently completed a rulemaking that will address mercury emissions from utility boilers, both existing and new. It is in this context that the cost-benefit analysis recommended by this comment should be performed.

In addition, coal washing plants and coal wastes also pose their own threats to the natural environment. While these threats can be managed, a benefit of the proposed mine-mouth

plant power plant is that such threats would be avoided altogether at the plant.

85. Coal washing is misrepresented in Appendix J of the application, as it mischaracterizes impacts and costs of coal washing. It is neither an accurate nor balanced document and should not be relied upon.

The application does not misrepresent coal washing. Prairie State conducted a reasonable evaluation of the cost impacts and the environmental and energy impacts that would accompany the combination of coal washing and scrubbing. With respect to the costs impacts, Prairie State accounted for both costs and savings that would result from coal washing, to address the net changes in costs. While the analysis in Appendix J of the application may not be as clear one might like, this does not mean that it is inadequate to show that the various impacts of washing coal for this mine-mouth power plant would be excessive.

86. The application incorrectly concludes coal washing is technically infeasible for an Illinois No. 6 coal. This conclusion is ludicrous. Coal washing is widely practiced on all forms of coal including Illinois No.6. Many existing mines in Illinois have coal washing facilities. In fact, Peabody washed coal for 33 years at the nearby Marissa mine that served the Baldwin plant.

As previously explained, coal washing is not eliminated on the basis of infeasibility. Incidentally, coal washing is not performed on all types of coals. For example, sub-bituminous coals are not washed. Thus, the coal supply for the Baldwin plant is no longer washed.

87. The emission rates from the proposed plant are based on a heat rate of 10,000 Btu/Kw-hr. This heat rate is extremely high due to the low quality run-of-the-mine fuel proposed for use at the plant. The failure to have a more efficient plant results in increased emissions, including greenhouse gases.

The emissions of the proposed plant are not calculated from the heat rate of the proposed coal-fired boilers nor is the <u>net</u> heat rate of the boilers, nominally 10,000 Btu/kw-hr, extremely high. The starting point for calculating the emissions of the plant is the size of the boilers, expressed in terms of heat input to the boilers, mmBtu/hour. The quality of the coal supply to the boilers is only one factor affecting the boilers' heat rate. It is also a factor that is offset by electrical energy consumed in washing the coal, a factor that is not considered by this comment, which looks only at the boilers.

Even for boilers, by themselves, other more significant factors for the heat rate are the steam temperature and pressure that are achieved, the temperature of the flue gases after the air pre-heater, the level of excess air, the level of unburned carbon in the ash, and the temperature of the cooling system for the power cycle, all of which determine the thermodynamic efficiency of the boiler. As previously explained, given the capital cost of the proposed plant and its long operating life, one should assume that Prairie State will design and develop the most efficient plant that it can given the technology that is currently available and its costs. Present regulations as well as future regulations, which will almost certainly

address CO_2, also provide a clear incentive for Prairie State to develop an efficient plant.

It is also important that any comparison between power plants be conducted on the same basis. Even if the comparison is performed looking at the power plant, ignoring other energy consumed in the generation of electricity, it is important that the comparison be on the same basis. It is preferable that this be in terms of net electrical output, i.e., electricity put on the grid, after accounting for the "parasitic" load at the plant consumed in operating the boilers, handling fuel, running the cooling system, etc. In this regard, various plants may account for the parasitic load differently, depending upon their organizational structure, especially if a unit is being added to an existing power plant.

88. Prairie State's application misrepresents the costs of coal washing because it does not discuss its benefits for power plant operation, as it reduces a plant's fuel handling costs, boiler costs including capital and operational costs, and control device costs including capital and operational costs. Coal washing also significantly reduces forced outages, lowers maintenance costs, and increases boiler efficiency. One 1983 study by TVA and USDOE developed mathematical models that quantified the detrimental impact of higher ash, sulfur and moisture on boiler efficiency, maintenance costs, and forced outages. While the context and examples in this paper are focused on existing plants, the conclusions also apply to new plants such as the proposed plant. The lost annual revenue alone from forced outages caused by using unwashed coal would dwarf the annual costs of washing found in Appendix J.

Prairie State's evaluation of coal washing did account for these factors, including an increase in boiler operating costs with unwashed coal. However, as noted in the comment, the TVA study addressed <u>existing</u> boilers that would not have been designed for unwashed coal. Accordingly, the data in the TVA study cannot be relied upon for an appropriate estimate of the increased operating costs for boilers that would be designed to burn unwashed coal. Prairie State's data shows that the increase in boiler operating cost is not inconsequential but not sufficient to tip the economic analysis in favor of washed coal.

89. Prairie State claims that its plant is different, because unlike existing plants, the plant would be designed for unwashed coal and will not be subject to high levels of unplanned outages. However, Prairie State fails to support this assertion with any data that would inform a reasoned review. Where are the plants that currently burn unwashed, high-sulfur, high ash, and mine-mouth coal? Such plants did exist at one time. In Illinois, for example, the Kincaid power plant opened in 1967 –1968, with using unwashed, 4% sulfur, mine-mouth coal. It used this unwashed coal until about 1976, when the plant's owner insisted that the coal be washed. Over the years, the plant switched coal a number of times. First to low-sulfur coal from Utah, then to low-sulfur coal from the Powder River Basin. Today, the Kincaid plant wins awards for fewest outages. No one single factor accounts for this success, but reduced wear and tear on the plant from lower-sulfur and lower ash coal is among the factors that are important. Kincaid is not alone. Many plants began their lives using mine-mouth unwashed coal and changed to washed coal. Using unwashed mine-mouth coal is not a new idea. It has been tried and found to be less optimal in the market relative to coal washing for a combination of environmental and operating reasons. While

technology has improved, the underlying environmental and operating reasons for using washed coal have not changed.

The fact that the existing power plants in Illinois have switched to Western coal does not demonstrate that appropriately designed new boilers cannot burn unwashed coal without excessive operating and maintenance costs. The factors that have resulted in existing power plants switching their coal supplies are also more complex than implied in this comment. For example, the Kincaid plant, which is almost 40 years old, was a "regulated utility" subject to oversight by the Illinois Commerce Commission (ICC) until recently. This status guaranteed a revenue stream to cover the reasonable costs and expenses of operating the plant, subject to review by the ICC. When the plant was built, it was not equipped with high-efficiency ESPs, nor were such ESPs required at the time. When new particulate matter emission standards were adopted as a result of the original Clean Air Act of 1970, washing of coal would have been a technique to reduce emissions to comply with those rules with the original ESP. Ultimately, new high-efficiency ESPs were approved and installed at the plant to comply with the new particulate rules. More recently decisions about the coal supply used at plants like Kincaid, which are not equipped with scrubbers, are affected by the costs of SO_2 allowances under the Acid Rain Program. Certainly, the fact that the Kincaid plant is <u>currently operating effectively with an unwashed coal</u>, suggests that coal washing is not essential for reliable boiler operation.

90. The operating costs of a coal washing facility are dramatically overstated. Prairie State assumes \$3.00/ton of processing costs for raw coal. The national average is \$2.00/ton.

Notwithstanding the conclusion of the commenter, this comment confirms the cost of coal washing used by Prairie State. Given the costs associated with "deep washing" of coal and a new or rehabilitated coal-washing facility, the cost of coal washing for the proposed plant should be significantly higher than the current average cost for coal washing.

91. Costs of SO_2 scrubbers are understated. In Appendix J of the application, Prairie State reports annual operating costs (including capital recovery) as \$19,703,000. By comparison, USEPA and U.S. Department of Justice (USDOJ) allege that one scrubber on the Baldwin Unit 2 (584 MW) in 1988 would have an annual cost of \$27,000,0000. For a plant the size of Prairie State's, that suggests 1988 annual costs approaching \$69,000,000 or more since the coal utilized in the plant is not washed. Scrubber costs have fallen since 1988 so this estimate could be too high. In its comments on SO_2 scrubbers, Carmeuse Lime estimates the annual costs of a scrubber for a boiler at the proposed plant at around \$50,000,000. The failure by Prairie State to provide a plausible value for the cost of a scrubber renders its BACT comparisons useless. The Illinois EPA cannot rely upon the Prairie State conclusions.

    SO_2 scrubber and wet ESP costs are understated in the evaluation of coal washing, which estimates the combined costs at \$35,207,000. A more appropriate figure would be above \$80,000,000. The cost of a scrubber, wet ESP *and* coal washing costs would be *less* than the cost of a scrubber and wet ESP using unwashed coal. As noted earlier in these comments, the revenue gained from fewer forced outages that result from burning a washed coal dwarf any coal washing costs. However, coal washing also reduces the capital cost and operating costs of a scrubber considerably. About 35% less limestone is needed in the scrubber using a washed coal.

The observations in this comment, as they address total costs of scrubbers, even if valid, are not significant to the evaluation. This is because coal washing would not eliminate the need for scrubbers or wet ESPs on the proposed boilers. This comment also does not demonstrate that the capital or operating costs for add-on control would change significantly if the coal were washed. The cost of limestone is only one factor in the operating cost of a scrubber, which based on data for the proposed plant would be only about \$20 to \$25 per ton of SO_2 controlled (1.7 tons limestone per ton controlled SO_2 at nominal \$11/ton for limestone). By comparison, to control one ton of SO_2 by deep of washing, assuming 100 percent benefit for emissions reduction, the cost for mining additional coal, by itself, would be over \$70 (8 tons of coal at nominal \$9/ton), not to mention the costs for washing over 35 total tons of raw coal.

92. Prairie State unrealistically claims that the cost of disposing of combustion waste from the boilers would be only \$3.00/ton. In their comments, the United Mine Workers state that disposal costs would be at least \$12.00/ton. This is supported by cost data reported to USDOE Energy Information Administration for combustion waste disposal in Illinois, Maryland, Massachusetts and Wisconsin. Disposal costs are dependent upon the extent of controls (e.g., liners) at the disposal site and the distance to the site. These states were selected for comparison because they are believed to have better controlled disposal sites, in which some form of liner is likely. This data shows that the costs for waste disposal at the proposed plant would be as large or larger than the estimates provided by the United Mine Workers. Attachment A details the information on individual plants.

The data accompanying this comment does not support the conclusion that is reached by the commenter. The data shows great variability in the current costs for disposal of combustion waste. In Illinois, these costs range from \$2 to \$43 per ton for the 15 plants that provided such data, with an average cost of \$10 per ton. Similar ranges of data are provided for a smaller number of plants in each of the other states. This generally supports a conclusion that the cost of disposal for combustion waste is specific to a particular plant. Beyond this, the cost projected by Prairie State is within the range of historical data. It is at the low end, similar to the cost for waste disposal at the nearby Baldwin power plant, as should be expected for a plant that is large, so as to benefit from economies of scale, with a local waste disposal facility.

Moreover, if Prairie State has underestimated the cost of combustion waste disposal, the further question that must be answered is whether Prairie State has also underestimated the cost of coal waste disposal. This is because the relevant issue for the evaluation of the coal washing is the relative costs for disposal of combustion waste and coal waste.

93. Research and improvements are occurring in coal washing technology that address the problems with historical coal washing technology. For example, The Illinois State Geological Survey reports on a project with the Illinois Clean Coal Institute to use a motorless washing process that reduces the amount of coal fines that end up in the waste slurry from washing.

This research is certainly occurring and is critical for the power plants that require washed coal and the mines that serve them. However, this research also confirms the difficulties of the current coal washing process, which these efforts are attempting to mitigate. In particular, an article describing the particular project cited in these comments remarks on "…the inefficiency of current coal processing methods and their high capital and operating costs." It also indicates that the goal of this innovative new process is to reduce the amount of material placed in tailings ponds and to create a coal blend that more closely meets Clean Air Act standards. The information does not indicate that this process would eliminate coal tailing ponds or produce a cleaned coal for the proposed plant that would bypass the need for high-efficiency SO_2 scrubbing.

94. The BACT analysis must consider the State's subsidies available for Prairie State's proposal before rejecting coal washing. Illinois cannot have it both ways. It cannot both offer subsidies and then say these subsidies are not available for consideration in the BACT analysis.

An analysis of cost-effectiveness does not require consideration of possible subsidies. Moreover, the subsidies available under Illinois law are a minor factor in the overall development of the proposed plant. This is particularly true when compared to the guarantees of income provided to regulated utilities in other States or the grants that have been provided by USDOE for IGCC pilot projects.

95. Absence of coal washing is one of the primary reasons why the emission limits for the proposed plant are set so high for PM, SO_2 and mercury.

The emission limits for PM and mercury are not affected by and are independent of whether the coal supply for the plant is washed. The primary reason why the emission limits for SO_2 are set where they are is the sulfur content of the local Illinois coal being used at this mine-mouth power plant. While the scrubbers on the boilers are very effective in controlling the SO_2 that is formed when this coal is burned, the scrubbers cannot control all the SO_2 emissions. At this time, the level of performance for the scrubbers for SO_2 that is appropriate to be set as an enforceable limit on the proposed plant is 98 percent control. While coal washing could potentially provide some additional reduction in SO_2 emissions on top of this very high level of required control, the amount of such reduction is not large given the extent to which SO_2 emissions would otherwise be controlled by the scrubbers. Coal washing would also be accompanied by impacts that are excessive for the amount of additional emission reduction that would occur, as previously explained.

96. Coal washing would allow the use of baghouses to control PM from the coal-fired boilers. Baghouses are the most effective device for controlling PM and mercury from a pulverized coal boilers.

Coal washing would not provide sufficient reduction in the sulfur content of the coal supply to the boilers to assure that baghouses would be reliable control devices. A critical issue for the reliable performance of baghouses is acid corrosion due to the presence of sulfuric acid mist.

This is a concern even at the levels of uncontrolled SO_2 and sulfuric acid mist that would accompany washed coal. As such, coal washing would not allow the benefits claimed by this comment, even if such claim were accurate. It is also inappropriate to broadly claim that baghouses are the most effective device to control particulate and mercury emissions from pulverized coal boilers, since they would not be effective for the proposed plant.

Careful consideration for the proposed plant leads to the conclusion that the most effective control devices for the plant are the ones that have been selected. The ESP provides effective, reliable control of filterable particulate. The wet ESP provides effective control of condensable particulate, for which baghouses are not generally considered particularly effective. The combination of an SCR and scrubber will facilitate conversion of mercury to the oxidized form, for effective collection by the SO_2 scrubber. To the extent that significant levels of elemental mercury are still present in the flue gas, provision is made for use of a control system specifically for mercury, i.e., sorbent injection, to collect elemental mercury.

97. Why do coal washing plants pose a concern for compliance with water quality standards?

One phase of wet coal washing results in a waste coal slurry (a mixture of coal fines and water). This slurry must be appropriately disposed of and excess water from the disposal operation must either be recycled back through the washing process or discharged off-site to the waters of the State.

In 2000, a new interpretation of 35 IAC 406.203 changed the approach to the establishment of effluent limitations for sulfate and chloride concentrations in National Prevention Discharge Elimination System (NPDES) permits for coal mines and coal mine related discharges. This interpretation requires discharges from such facilities to comply with the applicable water quality standard in 35 IAC Part 302 unless the discharge qualifies either for allowed mixing or establishment of a mixing zone in accordance with 35 IAC 302.102, so that the water quality standards are not violated in the receiving stream. It is difficult for the discharges from coal washing facilities to meet these more restrictive requirements, which apply to both new facilities and existing facilities upon renewal of their NPDES permits. The inability of certain existing coal washing facilities to meet the more restrictive discharge limitations have led these facilities to install closed circuit (non-discharging) systems for coal slurry, to implement underground injection of associated waste water, or to eliminate coal washing entirely, if they are able to do so. Although, the elimination of coal washing is the preferable option from a waste and water quality perspective, it is only feasible if the customers for the coal from the facility have the capability to use unwashed coal.

98. Coal washing is beneficial as it lowers transportation costs when coal is shipped from a mine.

This is correct. While this is clearly not the only benefit for coal washing, it is one of the simplest to understand. This benefit is further increased if coal ash cannot be disposed of at the power plant and must also be transported off-site, so that rock and ash in the coal must be transported twice.

BACT – Sulfur Dioxide (SO_2)

99. The draft permit proposes BACT for SO_2 for the boilers as 0.182 lb/mmBtu, 30-day rolling average, achieved with wet scrubbing. The recent PSD permit for Indeck-Elwood in Illinois and the proposed WE Power project in Wisconsin both have lower BACT limits of 0.15 lb/mmBtu. Considering that the high inherent sulfur content of the mine-mouth coal to be combusted at the proposed plant results in an SO_2 emission rate that is above 0.15 lb/mmBtu, the BACT determination also should include an enforceable 30-day rolling average minimum percent control efficiency for the SO_2 control system.

Upon further review, BACT for SO_2 for the coal-fired boilers has been supplemented with a requirement for 98 percent control of SO_2 emissions, as recommended by this comment. Given the nature of the performance data from existing power plants upon which the value for this efficiency limit is based, this limit has been applied on an annual basis (running total of 12 months of data). In addition, there were concerns about correlating SO_2 emissions data collected by continuous emissions monitoring with data for sulfur content of the coal supply, given the very high level of control that is being required. In this regard, the SO_2 efficiency of scrubbers is routinely determined from uncontrolled emissions calculated from the sulfur content of the fuel supply. This form of data, as must already be collected pursuant to the NSPS for coal-fired boilers, is the basis for actual data on the performance of SO_2 scrubbers relied upon by the Illinois EPA in setting the 98 percent control efficiency requirement for the scrubbers.

There was also a desire to have an actual level of performance for the SO_2 scrubbers that approaches the limit, without an even larger margin of safety, as needed with even a limit that is applicable on a monthly basis to account for normal variability in operation and performance of control systems when considered on a shorter time period. The data compiled by the USFWS indicates that a control efficiency requirement applied on a 30-day average would have to allow about 50 percent more SO_2 emissions than the annual limit that is being set, that is, an SO_2 control efficiency limit of about 97 percent, rather than the required control efficiency of 98 percent.

100. Carmeuse Lime is concerned about the selection of a limestone-based scrubber over a “magnesium-enhanced lime” scrubber for the proposed 98% removal rate for SO_2 and proposed SO_2 BACT limit of 0.182 lb/mmBtu. Magnesium-enhanced lime scrubbers have achieved higher SO_2 efficiency than 98% at power plants that fire high-sulfur coal, which should have been considered in the BACT analysis. Carmeuse has SO_2 removal results for a magnesium-enhanced lime scrubber that demonstrate 98.4 % SO_2 removal over a long-term and greater than 99% SO_2 removal in short-term tests. The cost of SO_2 scrubbing using magnesium-enhanced lime does not increase substantially when SO_2 removal is increased from 98% to 99%. Therefore, SO_2 BACT for the proposed plant must require at least 98.4% removal and a limit of no more than 0.146 lb/mmBtu.

These comments helped support the Illinois EPA’s decision to set the control efficiency limit for the coal-fired boilers at 98 percent. The comments include performance data for plants

that have achieved greater than 98 percent control efficiency. They identify one form of scrubbing technology, use of lime with a high magnesium content, that can reasonably facilitate a higher level of SO_2 removal, if it is not achievable with conventional limestone scrubbing. However, there is not an adequate body of data for performance at 98.4 percent to set this level of performance as BACT.

While BACT must be based on the maximum degree of reduction, the corresponding level of performance need not reflect the lowest possible emission rate or the highest possible control efficiency. Even assuming that the cited control efficiency was widely recognized as the requisite BACT performance level, it is often appropriate for a permitting authority to set a limit that will allow a source to achieve compliance on a consistent basis, provided that the underlying controltechnology is properly operated and maintained. The difference between 98.4 percent control efficiency as actually achieved by SO_2 scrubbers, as reported in these comments, and the enforceable limit of 98 percent control that has been set for the proposed plant, could easily be considered an appropriate "safety factor" in this BACT limit for SO_2 emissions. It reflects operation in normal practice at a level that is 20 percent better than the applicable limit that has been set for the proposed boilers, that is, at 98.4 percent actual control efficiency, compared to a required control efficiency of 98 percent. Such a safety factor would be particularly appropriate with the data cited by this comment because it is unclear that the control system being pointed to consistently achieved 98 percent control, even on an annual basis. In this sense, while 98.4 percent control was achieved at times, the comment does not show that 98.4 percent control is achievable on a continuing basis.

101. BACT was not required for SO_2 emissions from the proposed boilers. The draft permit would limit SO_2 emissions to 0.182 lb/mmBtu, on a 30-day average. The BACT analysis that this limit is based on is incomplete, inadequate, and inconsistent with the NSR Manual and the top-down BACT process. This is not BACT for SO_2 because the BACT analysis did not evaluate all technically feasible technologies and thus did not select the top technology. Further, these limits do not represent the "…maximum degree of reduction…" as required by the definition of BACT. Lower SO_2 limits have been achieved and permitted.

The permit recognizes the use of wet scrubbing as BACT for SO_2. Scrubbers are routinely used on pulverized coal boilers that burn higher sulfur coals, which require highly effective add-on control for SO_2 emissions. The emission rates and associated levels of SO_2 control that are achieved by or required of new boilers with wet scrubbers are comparable to or better than those of new circulating fluidized bed boilers.

The BACT determination for SO_2 ultimately reflected the most effective control system deemed achievable. The comment suggests that other technologies are available that enable lower SO_2 limits to be achievable. The fact that lower SO_2 emission rates have been achieved in practice at other plants does not demonstrate that those rates should determine BACT for the proposed plant, particularly as those other plants start from lower levels of uncontrolled SO_2 emissions as they use lower sulfur-content fuels.

102. BACT is "an emissions limitation… based on the maximum degree of reduction *for each pollutant*…" The applicant did not perform a top-down BACT analysis for SO_2 alone or for

sulfuric acid mist alone, as it should have done. Instead, it performed a top-down analysis for SO_2 and sulfuric acid mist ("SAM" or H2SO4) combined. (App., Sec. C.6.2.) As a result, it did not identify the correct removal efficiency for either pollutant, and it did not identify and evaluate all of the available control technologies for each pollutant.

The nature and relationship between emissions of SO_2 and sulfuric acid mist are such that the BACT analysis was properly performed. In addition, the permit also reflects an appropriate determination of BACT for SO_2 and sulfuric acid mist with appropriate limits established for both pollutants.

In this regard, both SO_2 and sulfuric acid mist have the same origin, i.e., sulfur contained in the coal supply to the boilers, which is oxidized during combustion. Control measures that are effective in controlling SO_2 emissions also control sulfuric acid mist emissions. SO_2 and sulfuric acid mist differ as sulfuric acid mist reflects the further oxidation of a smaller amount of the SO_2 that is formed during combustion, from SO_2 and SO_3, a process that continues as long as SO_2 is present in the flue gas (and then continues in the atmosphere). Sulfuric acid mist is formed in the boiler when the SO_3 combines with moisture. Accordingly, the "basic" control of these pollutants can be looked at in coordinated fashion, in terms of SO_2, followed by consideration of whether further controls beyond those for SO_2 are appropriate specifically for emissions of sulfuric acid mist.

The evaluation of the basic control of these pollutants, in terms of SO_2, is addressed extensively in response to other comments. Wet scrubbing is the most effective add-on control device for emissions of SO_2.

For sulfuric acid mist, there are three basic control techniques: (1) introduction of various additives into the furnace or combustion chamber of the boiler, which act to inhibit the formation of SO_3 and absorb sulfuric acid mist that is formed; (2) injection of various sorbents into the flue gas to absorb and collect SO_3 and sulfuric acid mist as a solid with the primary particulate matter control device; and (3) use of a wet electrostatic precipitator (WESP) as the final unit in the add-on control train of the boiler to specifically collect and neutralize SO_3 and sulfuric acid mist as a liquid. Of these techniques, the use of a WESP is considered the most effective, e.g. it is commonly used on plants producing sulfuric acid commercially. In addition, WESP are preferable for control of sulfuric acid mist, as they are considered more effective than either fabric filters or dry electrostatic precipitators for control of fine particulate matter.

The BACT emission limit set for sulfuric acid mist, 0.005 lb/million Btu, is identical to the limit set for Wisconsin Public Services Weston 4 project, and more stringent than the limits set for Longview Power (0.0075 lb/million Btu) and Wisconsin Electric's Elm Road Plant (0.010 lb/million Btu).

103. The most effective control technologies were not identified. The Illinois EPA concluded in the project summary that "[b]ecause Prairie State is proposing to use the most effective control system, an economic evaluation of this control system is not required." However, because the BACT analysis did not include all feasible technologies, including the most

effective, the proposed SO_2 BACT emission limit is not BACT. The first step in the top-down BACT process is to identify all "available" control options. (NSR Manual, Sec. III.A.) The applicant identified four classes of SO_2 control technologies – wet scrubber/wet ESP, wet scrubber, dry scrubber, and coal washing -- which it ranked according to a control efficiency for the class. (App., Table C.6.2-1, p. C-38.) However, these classes of control technologies are incomplete. Further, these classes contain a number of separate and distinguishable control technologies that are individually able to achieve higher SO_2 removal efficiencies than the 98% removal selected for the proposed plant.

The term "wet scrubbing" covers a class of SO_2 control technologies that scrubs flue gas with a slurry of lime or limestone. This class includes a number of processes, some of which have SO_2 removal efficiencies of over 98% on high sulfur coals. The processes that have demonstrated greater than 98% SO_2 removal and for which vendors offer guarantees greater than 98% are magnesium enhanced lime scrubbers and the Chiyoda CT-121 bubbling jet reactor. Further, design enhancements and additives are available that can increase removal efficiencies above 98% for other processes within this general class. The BACT analysis should be revised to evaluate these technologies and a 99% SO_2 control efficiency, which they are all capable of achieving.

Magnesium-Enhanced Lime scrubbers are a variation of the standard lime scrubber, except they use lime that contains up to 6 percent magnesium oxide as well as calcium oxide. To achieve the same effect, lime or limestone based systems require a high liquid-to-gas ratio (and therefore high power consumption), and sometimes the use of additives to approach the same removal efficiencies. Some vendors offer enhancements to the basic lime or limestone scrubber process selected by Prairie State that could increase the SO_2 removal. These include the use of a spray tower, performance enhancement plates, and the use of additives, such as dibasic acid.

The distinctions between different types of scrubber designs made in this comments are not relevant for the purposes of the BACT determination. Rather they reflect different designs of wet scrubbers or enhancements to a particular scrubber design. In this regard, commercially available scrubbing technologies for coal-fired boilers all rely on calcium (either, as present in limestone, CaCO3, or in lime (CaO) produced from limestone) as the chemical sink to react with SO_2 (and SO_3), ultimately forming gypsum ($CaSO_4$). The fundamental issue for wet scrubbers is setting the SO_2 emission rate or level of control efficiency that a scrubber must be designed to achieve. This does not necessitate an exhaustive review of all the different variants of scrubber technology.

104. The Pahlman process is a multipollutant removal process offered by EnviroScrub. It has been demonstrated to achieve 99.8% SO_2 control on a range of coals, including eastern bituminous, western Powder River Basin, and a blend of Powder River Basin and eastern coal at tests at DTE Energy, Minnesota Power's Boswell Energy Center, and Ameren Energy's Hutsonville Power Station. Other multipollutant removal processes have also achieved SO_2 removals of 98% to 99%.47

Control technologies that are not yet commercially available and are still being evaluated and

demonstrated, as reported in this comment, such as the Pahlman process, do not have to be evaluated in a BACT determination. This conclusion is supported by the Top-Down process for determining BACT, which emphasizes that the available control technology options identified in the first step of the process must possess some practical potential for applicability to a proposed project. The NSR Manual also recognizes the difference between control technologies that have been successful in practice on full scale operations and technologies that are still being researched and tested, which need not be considered available for purposes of determining BACT. In this regard, the provisions of the PSD rules are very clear that innovative control technologies need not be considered in a BACT determination. This is certainly sound policy for the proposed plant, given the amount of SO_2 emissions that must be reliably controlled. The SO_2 control technology underlying the BACT determination for the proposed plant must be a mature technology whose general capabilities and performance are well proven. Wet scrubbing is such a technology.

105. Although some of these enhanced SO_2 control technologies have not been demonstrated on the specific coal that would be used by the proposed plant, the technologies are still considered "demonstrated" if they are "available" and "applicable." A technology is "available" if it can be obtained through commercial channels. It is "applicable" if it can be reasonably installed and operated on the source under consideration. (NSR Manual, Sec. IV.B.) This approach is widely used to make BACT determinations. For example, an USEPA BACT expert recently made SO_2, PM10, and NOx BACT determinations for the Baldwin plant in Illinois. He concluded: "The control alternatives evaluated should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. In addition, the technology that will achieve the greatest emission reduction technically possible…is considered available for BACT purposes, must also be included as a control alternative and usually represents the 'top' alternative."

The USEPA guidance on BACT determinations is correctly paraphrased, i.e., a control technology does not have to be demonstrated on a particular type of coal to be considered a demonstrated technology. However, it is relevant that Mr. Haber's statements appeared in introductory material accompanying his analysis of BACT for the Dynegy Baldwin power plant. His position on BACT is found in the main body of the report and focuses on established control technologies for coal-fired power plants. In particular, Mr. Haber recommends wet scrubbing for control of SO_2 emissions from the boilers, combustion control and SCR for control of NOx emissions, and ESPs or baghouses for control of particulate matter.

Notwithstanding the aforementioned, the Haber document did not provide the type of information that could reasonably be relied upon in the BACT determination for the proposed plant. This conclusion is warranted given the nature and origin of the document, which was developed in the adversarial context of a lawsuit initiated by the federal government. The Haber document can fairly be regarded as a product of litigation, where each party postures for its best legal argument before any settlement negotiations. Such a process should be contrasted with the desired objectivity of a top-down methodology for determining BACT. Because this document was prepared for purposes of litigation rather

than a conventional evaluation of BACT, it was not appropriate for the Illinois EPA to have employed the document's conclusions or underlying assumptions in the BACT determination for the proposed project. The Haber document, as it was prepared by an expert for one side in the case, must be treated as an advocacy document. Notably, the outcome of the Dynegy lawsuit which addressed compliance with the PSD program as reflected in the proposed Settlement Agreement may be considered more meaningful than the Haber document or other documents provided by either the USEPA or Dynegy in this case.

106. The BACT analysis for SO_2 did not identify combinations of techniques to control SO_2. One combinations that would be more effective than the use of a 98% efficient scrubber , which was selected as BACT. One option is coal washing plus an add-on SO_2 control device. Coal washing was evaluated individually and was reported to have a low SO_2 control efficiency, 20 to 25%. However, coal washing was not evaluated in combination with add-on SO_2 control device. If the coal were washed to achieve only 20% SO_2 removal, and used in combination with a 98% efficient scrubber, the SO_2 emission rate would be 0.146 lb/mmBtu, corresponding to a 98.4% SO_2 control efficiency.

In fact, coal-washing in combination with scrubbing was evaluated. As explained in earlier responses, it was rejected for the mine-mouth coal supply for the proposed plant because it was not found to be cost-effective and because of its associated energy and environmental impacts.

107. Another option for combination of control measures is coal blending plus an add-on control device. The mine will produce a range of coal qualities. The BACT limit is based on the design basis coal, which has a sulfur content of 9.1 lb SO_2/mmBtu. Design coal is typically the worst-case coal. This coal will only be burned a small percentage of the time. A stockpile of low sulfur coal, from the proposed mine, or from another mine, could be maintained for blending with the feed when mining design coal. The Prairie State file does not contain sufficient information to evaluate this option. The Illinois EPA should require Prairie State to evaluate this option and support its analysis with a copy of the mine plan and coal quality data sufficient to estimate the range of sulfur contents in the feed coal and the percent of the time that design coal will actually be burned.

This is no longer a relevant option for the proposed plant given that a BACT limit for SO_2 in terms of control efficiency has been set. In this regard, the Illinois EPA has taken Prairie State's various representations about the performance of the SO_2 scrubbers on face value, that is, 98 percent control means 98 percent control, independent of the sulfur content of the coal being mined and used in the boilers at any particular time. In addition, it is doubtful, given other considerations that go into development of a mine plan, that the plan could actually guarantee consistently lower sulfur content of coal. Such reliability would be needed if the technique suggested by this comment were to be relied upon as a means to set a lower limit for the plant, in terms of lb SO_2/mmBtu. Incidentally, the observations in this comment helped confirm the appropriateness of a BACT limit in terms of control efficiency, as 98 percent control would not otherwise be attained during periods when the actual sulfur content of the coal from the mine was below the design value.

108. The top-down BACT process has historically considered clean fuels, which led to the explicit incorporation of the term “clean fuels” in the federal definition of BACT in the 1990 Amendments to the Clean Air Act. The USEPA notified a power company almost 20 years ago that requiring low sulfur fuel is an acceptable technique to meet a BACT standard. See Hawaiian Electric Company v. US EPA. Thus, clean fuels, such as those represented by the limits in the limits in Exhibit 20 (NPS 5/04), should have been considered in the BACT analysis.

As explained in earlier responses, use of lower-sulfur coal from outside of the Illinois basin was considered. It was rejected because it was beyond the scope of this project, which is being developed as a mine-mouth facility, with ability to use similar regional coal as an alternative fuel during extended interruptions of the mine-mouth coal supply. It also would entail reliance on a fuel supply whose future cost and value is uncertain. National and local initiatives to reduce the emissions from power plants continue to increase the demand for low-sulfur coal by existing power plants whose circumstances do not justify or allow the retrofit of scrubbers. The cost of low-sulfur coal is also linked to the cost of crude oil, which is the source of the diesel oil for the long-haul trains that would be needed to bring the coal to the proposed plant.

109. Lower SO_2 limits have been permitted and achieved. The proposed BACT limit for SO_2 is 0.182 lb/mmBtu based on a 30-day rolling average. The National Park Service has compiled SO_2 emission limits that have been proposed, permitted, and/or achieved by coal-fired power plants. This list shows that there are many coal-fired power plants that have been proposed, permitted, and/or are currently meeting lower SO_2 limits than proposed for Prairie State. Most of these limits are for units burning a lower sulfur coal than Prairie State. However, this is irrelevant for the Prairie State BACT determination because BACT is an emission limit “based on the maximum degree of reduction…” The top-down process does not contemplate rejecting a low limit due to coal differences. (NSR Manual, Chapter B.) The burden is on the applicant to demonstrate why a particular limit achieved by another source, such as those listed above, cannot be met, regardless of the type of coal it burns. However, the BACT analysis contains no such demonstration.

The BACT determination contains an emission limit for SO_2, 98 percent reduction, that directly represents the maximum degree of reduction in emissions that is achievable for the proposed plant, as determined by the Illinois EPA. The data compiled by the National Park Service from the Harrison plant, which showed that SO_2 control efficiency greater than 98 percent was achieved in practice in certain calendar years, helped contribute to the Illinois EPA’s decision to include a limit for SO_2 control efficiency in the permit.

Moreover, the comment ignores the obvious implications that would arise from a BACT evaluation that mandated consideration of low-sulfur coal for a high-sulfur coal, mine-mouth power plant. This would, in essence, turn the fundamental nature of the project on its head.

110. The proposed SO_2 limits are not based on the maximum degree of SO_2 reduction that has been permitted or achieved in practice. Control efficiencies of 99% are feasible for the proposed plant. This lowers the 30-day SO_2 limit proposed in the draft permit by a factor of

two, from 0.182 lb/mmBtu to 0.091 lb/mmBtu, a limit that has been permitted and achieved at other plants.

While a limit of 0.091 lb/mmBtu may have been set and achieved at other plants, it was not accompanied by an emission limit set at 98 percent control, as has occurred for the proposed plant. For a plant being developed to burn high sulfur coal, like the proposed plant, it is appropriate for BACT limits for SO_2 to be set both in terms of a lb/mmBtu limit and a control efficiency requirement. In addition, 99 percent removal is considered a theoretical limit. It would require the scrubbers to be operated on a continuing basis, to achieve an SO_2 emission rate to the atmosphere that is half the emission rate being required with 98 percent control efficiency. It clearly would not provide the safety factor for compliance that is appropriate for a BACT limit.

111. SO_2 controls are capable of achieving a wide range of emission performance levels. In such cases, "the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases." (NSR Manual, p. B.23.) As discussed above, the most recent regulatory decisions and performance data indicate that 99% SO_2 control is feasible. "The most effective level of control must be considered in the BACT analysis… when reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provides a technical, economic, or energy or environmental justification to do otherwise." (NSR Manual, p. B.24.) The Illinois EPA should require that Prairie State either demonstrate that it is infeasible to comply with a lower limit based on a higher control efficiency, or the Illinois EPA should impose a lower limit based on using a low sulfur fuel (achieved by coal blending or coal washing) or by using post-combustion controls discussed in other comments that are capable of achieving a higher control efficiency.

This comment does not provide an adequate basis to set a BACT limit for SO_2. It shows that modern controls can frequently achieve very high levels of SO_2 control on a short-term basis. On a long-term basis, they also perform very well. However, the data does not show that they can reliably achieve greater than 98 percent control.

112. The control efficiencies of the scrubbers for washed coal are underestimated. Comments submitted by Carmeuse indicate the availability of 99% removal efficiency with Magnesium Enhanced Limestone (MEL) scrubbing. A 99% efficiency on a washed Illinois No. 6 coal would correspond to an emission rate of around 0.06 lb/mmBtu, or an additional 8,000 tons of SO_2 removed.

A preliminary engineering evaluation from a vendor of control technology does not provide a reliable basis to set a BACT limit that goes beyond the demonstrated performance of the control technology. Moreover, undue emphasis is placed on MEL scrubbing as a means to improve control efficiency. In practice, use of MEL scrubbing can also reflect a business decision about the relative costs of limestone and lime, given the lack of a local supply of limestone that can be used at a plant.

113. The control efficiencies of scrubbers for unwashed coal are underestimated._Prairie State uses the wrong scrubber efficiency on a washed coal. Appendix J assumes that if the sulfur content of the coal is reduced by 20%, the efficiency of the Prairie State scrubber falls from 98% to around 97% (Refer to Appendix J of the application). This conclusion is contrary to experience at operating plants, such as the Petersburg Plant in Indiana, and information provided by vendors of scrubbers.

For purposes of evaluating coal washing, the Illinois EPA has not relied solely on the approach taken by Prairie State. The Illinois EPA has also evaluated scenarios in which a change in sulfur content of coal would only result in a small lessening of the control efficiency of the scrubber.

113a. If the BACT limit for SO_2 is set at 0.182 lb/million Btu, as proposed, Prairie State could optimize the operation of the scrubber to meet this limit and not "overscrub," as it is feasible to do so.

This scenario is not likely, given the economic incentives created by the existing Acid Rain Program and the new CAIR for coal-fired power plants to minimize SO_2 emissions, as doing so reduces the costs for purchasing SO_2 allowances. However, as this scenario is theoretically possible, it was another reason that the Illinois EPA established a limit for SO_2 emissions from the boilers that explicitly addresses SO_2 control efficiency.

114. The AES Petersburg power plant in Indiana achieved scrubber efficiencies of 98 + % on an annual basis in 2003. The coal used at the plant is a washed bituminous coal from nearby mines, with an. equivalent uncontrolled emission rate of SO_2 of 5.25 lb/mmBtu, on an annual basis. This is very similar to the sulfur content of coal that would be expected from the Prairie State mine if the coal were washed. This data for the Petersburg plant shows that the proposed plant could wash the coal used at the plant and emit 0.1 lb/mmBtu of SO_2. To achieve this level of scrubbing the scrubbers at the plant had to be upgraded. In 2002, the Petersburg plant had an emission rate of 0.23 lbs SO_2/mmBtu with a reported a scrubber efficiency of only 96.2 to 96.8%. The performance in 2003 reflects changes to the scrubbers after more "rings" were added to the spray towers to reduce the amount of SO_2 "slippage."

The information accompanying these comments does not provide an adequate basis to require greater than 98 percent control for the proposed plant. In particular, for calendar year 2003, after physical upgrades to the scrubbers, the calculated scrubber efficiencies for Petersburg Units 1 and 2, as provided in this comment, were 97.95 and 98.27 percent, respectively. This does not demonstrate achievement of an actual level of control efficiency that would allow a limit higher than 98 percent control to be set with an adequate factor of safety. The data shows that the scrubbers at the Peterburg plant have achieved approximately 98 percent control on a long-term basis, i.e., in a particular calendar year. The Illinois EPA does not agree with the interpretation of the data made by the commenter with respect to coal washing, as the coal supply to the plant is a separate aspect of SO_2 emissions of the Petersburg plant unrelated to the scrubbers.

115. In four months during 1983 and 1984, the scrubber on Unit 33 at the Mitchell power plant in Pennsylvania, which is of magnesium-enhanced lime design, demonstrated more than 99 percent control of SO_2 emissions on 88 individual operating days. The maximum monthly average emission rate over this period was 0.029 lb/mmBtu, corresponding to a 99.72 percent SO_2 reduction.

This historical data does not provide an adequate basis to set a limit for the proposed plant for scrubber efficiency at greater than 98 percent. Further review of the circumstances under which this data was collected, as also provided by the commenter, shows that this data was collected as part of an 18-month demonstration period for the unit under a consent decree. Pursuant to the decree, the source was only required to install a scrubber with 95 percent efficiency and comply with an SO_2 emission rate of 0.45 lb/mmBtu. The data for the unit for 2004 collected under the Acid Rain Program shows that the unit is currently emitting approximately 0.166 lb SO_2/mmBtu, which is lower than 0.45 lb/mmBtu but much higher than the emission data provided for the demonstration period. Based on the sulfur content of coal during the demonstration period, the actual control efficiency of the scrubber is currently in the range of 97 to 98 percent.

116. Vendor data confirm that higher removal efficiencies are possible on an annual basis for both washed and unwashed coals. Some of this literature on pollution controls document deep sulfur reductions. In addition, in e-mail correspondence between Alstom and the Clean Air Task Force, Alstom claims that a new scrubber is available with 98% removal guarantees on a washed Illinois No. 6 coal.

As this information reflects general data provided in literature by vendors, this information does not show that greater than 98% control of SO_2 emissions is achievable on a reliable basis as is required for BACT. However, this information does provides additional confirmation that a BACT limit of 98 percent control is appropriate.

117. Prairie State's contends that coal washing will reduce the heating value of the coal supply.

This is incorrect. Prairie State has not stated that coal washing would reduce the heating value of the coal supply to the boiler, nor is that the result of coal washing. Coal washing improves the heat content in the coal supply to the boilers. It also results in waste from the coal washing plant that contains significant amounts of coal.

118. Scrubbers, precipitators, etc., all use significant amounts of the energy produced by a plant and thus affect the energy input/output balance. In Illinois EPA's view, precipitators or scrubbers could be exempted if an applicant were to merely state that the efficiency of the plant would be reduced if the plant were forced to incorporate such controls into its plans.

The Illinois EPA did not state that the energy consumed in washing coal is a basis to eliminate coal washing as a BACT option for the proposed plant. In this context, energy consumption is not a significant factor in the evaluation of coal washing as a supplementary control measure at the proposed plant. This is because coal washing also acts to improve the thermal efficiency

of a boiler slightly, so that the there is not a significant change in electricity consumption comparing coal scrubbing and coal washing to coal washing alone. Coal washing poses a concern for energy impacts as it involves converting fuel into waste in the washing process. This loss is significant, with about 20 percent of the fuel value of the incoming coal supply ending up on the waste pile.

119. The SO_2 emissions limit that could be established using low-sulfur western coal is at least 0.06 lb/mmBtu. The application should have evaluated the option of a power plant using low-sulfur western coal. A permit emission rate of at least 0.06 lb/mmBtu would be possible for such a fuel.

SO_2 limits achieved at plants using low-sulfur western coal are not a relevant basis to set BACT for the proposed plant, as the proposed plant would be a mine-mouth plant designed to use a particular coal reserve comprised of Illinois No. 6 coal.

120. Several permit applications have been filed recently for coal-fired power plants utilizing low-sulfur western coal. A proposed 270 MW CFB plant in Sigurd, Utah, seeks a limit of 0.05 lb/mmBtu. The design fuel is a bituminous coal with a sulfur content of 0.4%. The City Public Service of San Antonio application seeks a limit of .06 lb/mmBtu for a coal with a sulfur content no higher than 0.6%. Other permits, including AES in Puerto Rico are based upon 0.022 lb/mmBtu.

SO_2 limits proposed for plants that would use low-sulfur coals are not a relevant basis to set BACT for the proposed plant, as the proposed plant would be a mine-mouth plant designed to use Illinois No. 6 coal.

121. With the use of low-sulfur coal, Matt Haber of USEPA concluded that SO_2 BACT limit in 2002 is an emission rate of 0.095 lb/mmBtu based on 95 % scrubbing and assuming use of coal with 0.6% sulfur. (Best Available Control Technologies for the Baldwin Generating Station, Baldwin Illinois, Expert Report of Matt Haber, prepared for the United States in connection with United States v. Illinois Power Company and Dynegy Midwest Generation, Inc.)

When Mr. Haber evaluated BACT for SO_2 emissions at the Baldwin power plant as of 2002, he started from the coal supply being used at that time at the plant, i.e., low-sulfur western coal containing 0.6 percent sulfur, as is still being used at the plant. Mr. Haber did not address use of alternative sources of coal at the plant. Thus, the recommendation for control of SO_2 emissions cited in this comment does provide relevant information for the appropriate level of control for SO_2 emissions for the proposed plant, with its high-sulfur, mine-mouth coal supply. As noted by the comment itself, the control efficiency recommended by Mr. Haber for the scrubbers is only 95 percent, substantially lower than the 98 percent control efficiency being required for the boilers at the proposed plant.

122. There are numerous existing coal-fired power plants and permits for new plants that have SO_2 limits that are significantly more stringent than the limit proposed for Prairie State. A selection of six of those plants shows limits ranging from 0.10 to 0.167 lb/mmBtu. Also the

recently agreed-to BACT limit for the Longview plant, 0.095 lbs/mmBtu, annual average, must be considered.

The SO_2 limits pointed to in these comments are limits expressed in lb mmBtu. They do not reflect more efficient control of SO_2 emissions, but rather depict use of a coal supply containing less sulfur. The efficiency of SO_2 control underlying these limits, as also provided with the comments, ranges from 90 percent to 96.25 percent. For example, the Deseret plant in Utah with a limit of 0.10 lb/mmBtu, is using a local Western Colorado coal that contains only about 1.0 lb SO_2/mmBtu equivalent and is only required to scrub with about 90 percent efficiency. The limit for the Longview plant was originally set at 0.12 lb SO_2/mmBtu, based upon 97 percent control of emissions. Even after being lowered to 0.095 lb/mmBtu pursuant to a consent order, the limit for Longview only reflects 97.625 percent control of SO_2 emissions.

123. The BACT analysis fails to properly rank BACT options and select BACT. One of the units at the Petersburg plant in Indiana achieves 98.3% removal efficiency on a washed high sulfur coal on a year-round basis. Carmeuse has submitted comments showing 99% removal efficiency is possible for Illinois No. 6 coals. The Illinois EPA should assume that 99% efficiency is practical for scrubbers at this plant. The IGCC plant should be evaluated on a was*hed coal basis.*

The BACT analysis included an appropriate ranking of control options and appropriately set BACT for SO_2.

124. Prairie State would like to take advantage of the many economic subsidies available under Illinois law for power plants that use Illinois coal. However, efforts to promote Illinois coal are not an acceptable justification for the BACT determination for the proposed plant.

Programs in Illinois to promote use of Illinois coal are not the justification for the BACT determination. These programs are administered by agencies other than the Illinois EPA. The Illinois EPA made the BACT determination for the proposed plant in accordance with the federal PSD rules.

In addition, Illinois' programs to facilitate development of new power plants using Illinois coal are limited in scope and more accurately characterized as incentives. The two major features are a waiver of State sales tax on plant components and an "advance" on the State sales tax that a source would pay on coal purchased for a plant. This latter feature is not even available to Prairie State as the proposed plant is a mine-mouth facility.

BACT – Nitrogen Oxides (NO_X)

125. The draft permit proposes a BACT limit of 0.08 lb/mmBTU for NOx . The BACT limit should be set at least at 0.07 lb/mmBTU, which is being permitted in both the WE Power project in Wisconsin and the MidAmerican project in Iowa, or the record be developed to

support the higher NOx limit.

Upon further review, the BACT limit for NOx has been lowered to 0.07 lb/mmBtu, 30 day average, as recommended by this comment.

126. The draft permit contravenes the BACT limit for NOx, 0.08 lb/mmBtu, on a 30-day average. This is because elsewhere the draft permit would set a second NOx limit of 893 lb/hr, 24-hour average, (equivalent to 0.12 lb/mmBtu). A footnote indicates that a coal-fired boiler can comply with either limit, *viz.*, "As an alternative to this limitation expressed in pounds/million Btu [0.08 lb/mmBtu], the boiler may comply with the limitation expressed in pounds/hour." This would effectively allow the source to comply with a limit that is higher than has been determined to be BACT. The Illinois EPA should remove the footnote and clarify that both limits must be met, the 0.08 lb/mmBtu, 30 day average, as BACT and 893 lb/hr, 24-hour average, as related to air quality impacts.

The interaction of various provisions for NOx in the draft permit identified by this comment was not intended. The issued permit does not include that language that would suggest such an interaction, as requested by the commenter.

127. The application does not show that a limit of 0.08 lb/mmBtu, 30-day average, is equivalent to a 0.12 lb/mmBtu, 24-hour average. Further, the 24-hour limit is clearly not BACT, based on recent PSD permits. For example, the proposed Longview plant in West Virginia, which would burn a similar high sulfur coal, has a BACT limit of 0.08 lb/mmBtu, 24-hr average.

As explained above, the BACT limit for proposed plant has been set at 0.07 lb NOx/mmBtu, 30-day average. This is identical to the BACT limit ultimately set on a 30-day average for the proposed Longview plant.

128. BACT is not required for NOx from the proposed boilers. The Illinois EPA concluded that BACT for NOx is a limit of 0.08 lb/mmBtu, 30-day average. Lower NOx limits have been permitted and achieved in practice. The file contains no evidence that these lower limits are not achievable.

The limit for NOx proposed in the draft permit reflected a concern over conversion of SO_2 to SO_3 by the SCR. This was in part due to an unresolved problem related to this phenomenon at an existing power plant. Further information has confirmed that wet ESPs can be designed and operated to control such SO_3. Accordingly, the Illinois EPA agrees that a NO_x limit lower than 0.08 lb/million Btu is achievable.

129. There was no justification for not selecting the "top technology" for control of NOx. BACT is the lowest achievable emission level that does not have any adverse environmental, energy, or economic impacts. If the top technology is not selected, the reason for not selecting it "should be documented for the public record." The top technology is defined in the NSR Manual as "the 'top' control technology option that achieves the lowest emission level." (NSR Manual, p. B.9, 25 and 25.)

The "top" control technology for NOx has been selected for the coal-fired boilers, i.e., a combination of low-NOx combustion techniques in the boiler and add-on selective catalytic reduction (SCR). The limit set for NOx in the issued permit, i.e., 0.07 lb/mmBtu, is the appropriate limit for this technology to reflect the maximum degree of emission reduction.

As is evidenced from other responses concerning BACT for NOx, the Illinois EPA's determination of the BACT limit for NOx considered a wide range of information including information in USEPA's BACT RACT LAER Clearinghouse and comments received from the public.

130. Prairie State's application contains no rationale for selecting a BACT limit of 0.08 lb/mmBtu, 30-day rolling average, for NOx rather than a lower limit. In particular, it reports a proposed BACT limit of 0.05 lb/mmBtu from the application for the proposed Cash Creek power plant in Louisville, Kentucky but did not explain why this limit should not constitute BACT for its proposed plant. The application for the Cash Creek plant, which was prepared by Burns & McDowell for Cash Creek, states: "In order to establish a basis for identifying a NOx emission rate for this unit, Burns & McDonnell contacted suppliers and vendors, seeking those long-term removal levels that catalyst manufacturers would guarantee… An emission rate of 0.05 lb/mmBtu was established as the top level of control for this NOx BACT evaluation. This value is based on the performance guarantees we expect to be available from equipment suppliers." The BACT analysis should be revised to document why this limit should not apply. If cost is used, the analysis should include the savings for the NOx allowances that would otherwise have to be purchased under the NOx Trading Program.

In its application, Prairie State provided its rationale for selecting a limit of 0.08 lb/mmBtu when it proposed a BACT limit for NOx. At that time, in late 2002, this limit was lower than the BACT limit for any new coal-fired boiler. As determined by Prairie State, the average of the BACT limits for NOx for new coal-fired boilers at that time was only 0.14 lb/mmBtu. Prairie State rejected the limit of 0.05 lb/mmBtu for the Cash Creek plant as it was contained in an application for a proposed plant, not a permit.

The Illinois EPA rejected the limit for the proposed Cash Creek plant as being unrealistic. It did not reflect an incremental improvement in the performance of SCR technology, for which the lowest limits then being set were in the range of 0.09 to 0.1 lb/mmBtu. As explained by this comment, the 0.05 lb/mmBtu limit selected by Cash Creek was based on the <u>expected long-term</u> performance guarantees, which had not yet been obtained, and was not logically lower than the limits proposed for other new plants. It was not eliminated based on a cost evaluation. A relevant consideration for a BACT determination is the ability of the selected control measures, if properly operated and maintained, to comply with the limit selected as BACT for the life of the unit. Moreover, any consideration of the Cash Creek application is now questionable, as the Kentucky Department of Environmental Protection reported in a recent inquiry that the application for the Cash Creek project has been withdrawn.

Incidentally, even if cost had been used to eliminate the proposed limit from the Cash Creek application, it would not have been appropriate to consider the cost of NOx allowances. This

is because it would be inconsistent with the fundamental nature of the NOx Trading Program. The NOx Trading Program is intended to allow sources to seek the least expensive means to reduce NOx emissions, so as to minimize the overall costs of such reductions for society. As such, it is certainly an incentive for the operators of new power plants, like the proposed plant, to design and operate plants to minimize NOx emissions. However, the Trading Program is not intended to set a required level of control that must be achieved nor does it have direct consequences if a plant does not meet a particular emission rate. In contrast, BACT is a technology-based emission limit for which compliance is required. Factoring the cost of NOx allowances into an analysis for BACT could result in an overly stringent BACT determination that is distorted by such costs, particularly as the cost of NOx allowances should fall as the NOx Trading Program matures. It is also unnecessary as a matter of economics to consider the cost of NOx allowances, as it is a cost that directly applies through the life of a plant as an incentive to reduce emissions.

131. The information in the BACT analysis is incomplete. The Illinois EPA must consider all relevant information up to the date of permit issuance. Prairie State's analysis appears to have been completed in October 2002. However, additional, relevant information has since become available.

The BACT determination is based on current information. Prairie State supplemented its application with additional information to reflect developments at other plants. The Illinois EPA has also investigated developments with respect to other plants and investigated information supplied with comments.

132. Lower NOx limits are achievable. The information I have compiled indicates that BACT is a NOx emissions limit of no more than 0.05 lb/mmBtu, on a 30-day average. Other agencies have determined that BACT for NOx for coal-fired boilers is lower than 0.08 lb/mmBtu, on a 30-day rolling average. These determinations should be included in the applicant's BACT analysis and the lowest such determination, 0.015 lb/mmBtu, either accepted as BACT, or an analysis conducted that shows that there are collateral environmental, energy, or economic impacts that preclude each such limit for use by Prairie State.

The various pieces of information accompanying this comment do not show that a limit lower than 0.07 lb/million Btu, 30-day average, is achievable in the sense that is required to set BACT. While lower emission rates have been achieved in certain, relatively limited circumstances, this does not show that such limits can be met for the life of the boiler with proper operation, maintenance and repair of the control system. Normal variability and degradation over the operating cycle of the chosen control technology necessitate the incorporation of modest safety margins in BACT limits. Moreover, the BACT limit for NOx is identical to other recent BACT determinations for new coal-fired utility boilers.

133. The BACT analysis prepared by Matt Haber, a BACT expert in USEPA Region 9, for the Baldwin power plant in Illinois, in conjunction with a federal lawsuit, supports a lower BACT limit for the proposed plant. Mr. Haber concluded that BACT for NOx for Baldwin Unit 3 as of 2002 was 0.015 lb/mmBtu for a new unit and 0.020 lb/mmBtu, 3-hour average, for a retrofit unit, achieved using low-NOx burners, SCR, and a combustion optimization

system. This limit could be adjusted as high as 0.04 lb/mmBtu if a lower limit was demonstrated to be unachievable.

The limit for NOx recommended by Mr. Haber is significantly below the limit for NOx being required of other new boilers, to a degree that is unrealistic. It reflects ideal performance of the low-NOx combustion controls and SCR systems on the boilers, without any initial safety factor. As noted by the comment itself, Mr. Haber indicates that the BACT limit that is actually achievable for NOx may actually be two and a half times a value that is initially being recommended. A more telling piece of information from this lawsuit is the levels of NOx emissions that would be required under the Settlement Agreement for the Baldwin power plant, i.e., Boilers 1 and 2, which are equipped with low-NOx combustion controls and SCRs, , are subjected to a limit of 0.10 lb NOx/mm Btu on a 30-day rolling average.

134. Recent actions of the Texas Natural Resources Conservation Commission support a lower BACT limit for NOx. The Commission recently concluded that a NOx limit of 0.03 lb/mmBtu was "technically feasible in the commission's analysis, based on the literature and discussion with SCR vendors. REI [Reliant Energy Inc.] has awarded a contract for construction of SCRs on its four coal-fired boilers with an emission specification of 0.03 lb NOx/mmBtu, which supports the commission's view that the technology has the capacity to achieve this level." (26 TR 2, p. 557.) For coal-fired utility boilers, the Commission ultimately established NOx limits of 0.033 lb/mmBtu for the Dallas/Fort Worth nonattainment area and 0.040 lb/mmBtu for the Houston/Galveston nonattainment area. (26 TR 41, p. 8159.) These limits, which are equivalent to LAER, should have been included in the top-down BACT analysis.

The Illinois EPA has reviewed this action in Texas. It does not provide an appropriate basis to set a BACT limit for the coal-fired boilers at the proposed plant. As a general matter, this action cannot be applied to the proposed plant given the specific factual and regulatory circumstances in which it is occurring. It effectively represents a regulatory determination by the Texas Commission applying to certain existing boilers. For example, a NOx "limit" of 0.10 lb/mmBtu is set for utility boilers located in the Beaumont/Port Arthur ozone nonattainment area. In fact, these "limits" are not limits but "Emissions Specifications for Attainment Demonstration." Compliance with these <u>specifications</u> is to be determined in accordance with Texas' regulations that provide for system wide caps on NOx emissions, not unit-by-unit compliance. Accordingly, these specifications also apply on a mass-basis, not on a rate-basis, as provided by the federal NSPS. Moreover, applicable regulations appear to allow for such a cap to be exceeded with appropriate use of emission credits. Finally, subsequent to the actions reported in the comment, the Texas Commission appears to have raised the specifications for the coal-fired utility boilers in the Houston/Galveston area to 0.045 lb/mmBtu (0.050 lb/mmBtu for wall-fired units).

For new coal-fired utility boilers, Texas is considering applications in which the proposed BACT limits for NOx are about 0.07 lb/mmBtu, 30-day average. While the initial performance of existing boilers equipped with SCRs is better than this, Texas is concerned about factors that affect the performance of the SCRs over their operating life. Identified factors include flow dynamics, ash plugging, ash accumulation on catalyst, and catalyst

deterioration. Accordingly, Texas does not consider the guarantee provided by the manufacturer of an SCR, such as the guarantees obtained by Reliant for certain boilers, as an appropriate basis to set a limit or specification for NOx that would apply for the life of a unit. In this regard, Texas correctly observes that such guarantees represents contractual obligations from the SCR manufacturer for performance under specified conditions after construction of the system is completed. The performance of the system is not guaranteed over the life of a system. Thus, a prudent source seeks to obtain a guaranteed level of initial performance that is significantly better than the limit with which a unit must comply over its entire life time.

135. The letter written by the Georgia Department of Natural Resources to applicant, Longleaf Energy Station, concerning its application for a pulverized coal-fired power plant, supports a lower BACT limit. The emission levels cited in this letter should have been addressed in the BACT analysis.

> It appears that you have limited your consideration of potential BACT control technologies and corresponding BACT emission limits to those that you found in the RACT/BACT/LAER Clearinghouse (RBLC). This is not acceptable… In addition, the Babcock & Wilcox presented a paper titled "How Low Can We Go" at the 2001 Mega Symposium. This paper reports that there are emission control technologies for eastern bituminous coal that can achieve 0.016 lb/mmBtu NOx, 0.04 lb/mmBtu SO_2, and 0.006 lb/mmBtu PM-10…. Keeping in mind that the Permitting Authority must consider all information submitted through the comment period on the draft permit in assessing BACT, at the present time EPD is considering these levels as BACT.

This letter and the associated paper were present in the record for the proposed plant. The levels of emissions were considered by the Illinois EPA and found to be unrealistic for new plants that are currently being proposed. In this regard, it is significant that the authors of this paper concluded "In order for this combination of technologies to be commercially deployed, they must achieve high reliability, availability and capacity factors. This is achieved by employing advancement that are based on existing technologies and excluding those that have never been demonstrated beyond pilot scale." This observation supports the Illinois EPA's decision to regard this material as too speculative to be the basis of a BACT determination for the proposed plant.

In addition, discussion with the State of Georgia has confirmed that its current thinking for the proposed Longleaf plant for NOx BACT is a limit of 0.07 lb/mmBtu. It is also considering limits of 0.12 lb/mmBtu for SO_2 and 0.033 lb/mmBtu for PM10. In this regard, it should be noted that the design coal supply for the Longleaf plant would have moderate sulfur content, as a blend of Western low-sulfur coal from the Powder River Basin and central Appalachian coal.

136. A letter submitted by the USEPA for the proposed Longview plant in West Virginia supports a lower BACT limit for the proposed plant. This letter endorses a BACT limit of 0.04 lb/mmBtu, 30-day average for the Longview plant. This recommendation is based on the performance of the SCR systems at PPL's Montour plant in Pennsylvania. The

Pennsylvania Department of Environmental Protection subsequently wrote that it "… concurs with EPA's assessment that an appropriate BACT level for a pulverized coal-fired boiler controlled by an SCR system should be 0.04 lb of NOx/mmBtu on a 24-hour basis, instead of the 0.08 lbs/mmtu emission rate that has been proposed for the LongView plant." Conversations with Longview indicate a design basis coal with 7.5 lb SO_2/mmBtu and 25% ash, which is comparable to that for the proposed plant.

These letters submitted for the proposed Longview plant do not provide a basis to set the BACT limit for the proposed plant. They rely on the performance of the SCR systems at the Montour plant over the initial years of operation, which does provide an adequate basis to assess the long-term performance of the SCRs. Uncertainty about the overall performance of the SCRs is also confirmed by the period of initial operation. In particular, the basis of the design for the Montour SCR systems was 90 percent NOx removal at 7600 hours of catalyst life, from an inlet NOx level of 0.4 lb/mmBtu. However, the Montour plant has experienced an inlet level of NOx for the SCRs at 0.45 lb/mmBtu. With 85 percent removal reliably achievable by the SCRs just prior to replacing a layer of catalyst, the resulting NOx emission rate would be about 0.07 lb/mmBtu during the normal operating cycle of the SCRs.

In this regard it is also relevant that the West Virginia Department of Environmental Protection did not set a BACT limit of 0.04 lb/mmBtu for the proposed Longview plant. The WVDEP pointed to concerns about increased emissions of other pollutants (CO, VOC and sulfuric acid mist) as reason to reject this lower limit. Instead, the permit was issued with a limit of 0.08 lb/mmBtu, 24-hour average, and was subsequently supplemented by means of a Consent Decree with a limit of 0.07 lb/mmBtu, 30 day average.

137. A large number of coal-fired boilers have been retrofit with SCR systems to comply with the NOx SIP Call, 40 CFR Part 96. As retrofits, they represent the worst-case for cost and effectiveness of control because the design of the systems must accommodate the layout and other constraints imposed by the existing boilers. From the 2003 NOx CEMS data from the USEPA website for the best performing units, I calculated 30-day rolling averages for the ozone season for 11 separate units firing a wide range of coals, from low sulfur, Powder River Basin sub-bituminous coal to high sulfur bituminous coal. The highest reported 30-day rolling averages for these units range from 0.049 to 0.071 lb/mmbtu. Even lower NOx rates are likely during the 2004 ozone season, when sources must begin holding NOx allowances for their emissions. This data demonstrates that lower NOx emissions rates are achievable for the proposed plant than the proposed limit of 0.08 lb/mmBtu, 30-day average. In fact, the USEPA developed NSPS for the new coal-fired utility boilers based on only 90 days of NOx CEMS data. Additional data for the current ozone season will likely be available before the final action is taken on the application for the proposed plant and should be evaluated when it becomes available.

This data suggests that NOx BACT for the proposed plant is a limit of no more than 0.05 lb/mmBtu, 30-day average. This is consistent with a guarantee of 0.05 lb/mmBtu offered to Prairie State by CERAM, a catalyst vendor. It is also consistent with the NOx level proposed by Alstom, Prairie State's vendor, based on a similar high sulfur (4.3%) bituminous coal. Clearly, this limit is achievable based on CEMS data, has been offered by a vendor and has been proposed by the applicant's vendor for a similar coal. Therefore, Illinois EPA should require that the applicant evaluate this limit.

This data provides substantial support for a limit lower than 0.08 lb NOx/mmBtu, and was relied upon by the Illinois EPA in setting a BACT limit of 0.07 lb NOx/mmBtu for the coal-fired boilers at the proposed plant. On the other hand, this data does not demonstrate that lower emission rates can consistently be achieved by the SCR systems on these units or by the SCR systems on new units. This is because retrofit installations may be more costly, but are not necessarily less effective in controlling emissions. In addition, given the nature of the NOx SIP call, which entails trading of NOx allowances, sources were encouraged to select and install SCRs to maximize reductions of NOx emissions, thereby avoiding the need to add such systems at other units. As this data reflects the condition of the SCR systems when relatively new, it does not necessarily reflect the long-term performance of the systems. In addition, while allowance trading was not in effect in 2003, other factors may have encouraged rigorous operation in 2003, e.g., provisions to obtain allowances for early reduction in emissions. This is confirmed, as a review of 2004 data did not show significantly different results.

While a limit may be set based upon a small amount of data, as noted by the commenter with respect to the USEPA's last NSPS rulemaking for utility boilers, the amount of data has implications for the safety factor because consistent compliance must be contained within such limit. This is reflected in the limit set by USEPA for NOx in the NSPS, 1.6 lb NOx/MW-hour, which is roughly equivalent to 0.16 lb NOx/mmBtu.

Finally, preliminary information provided by vendors, as noted by this comment, does not provide an adequate basis to set a NOx limit. Vendors do not receive permits and are not subject to risk of enforcement if a control system fails to perform as predicted.

In summary, the emission data identified in the comment does provide strong support for a NOx limit of 0.07 lb/mmBtu. In particular, as compared to a NO_x limit of 0.07 lb/mm Btu, only one of the 12 units would have exceeded this limit at only 0.071. Three units closely approached 0.07 lb/mmBtu, with NO_x emissions of 0.069 or 98.5 percent of the limit. Four units operated with a maximum rate between 0.064 and 0.067 lb/mmBtu, or between 91 and 96 percent of the limit. The final four units had maximum rates of no more than 0.061 lb/mm Btu, or 87 percent of the limit.

Conversely, the data does not support a limit lower than 0.07 lb/mmBtu because it was not consistently achieved. For example, as compared to a possible limit of 0.065 lb/mmBtu, five of the units would have violated this limit, with NO_x emissions that ranged from 3 to 9 percent above the limit. Another three units would have been close to the limit, at 0.064 lb/mmBtu or 98.5 percent of the limit. Only two units would have operated at 90 percent or less of the limit.

138. It has been argued in the appeal proceeding for the proposed Thoroughbred plant in Kentucky that lower NOx limits are not achievable due to low boiler outlet NOx levels and poor coal quality. These arguments are not valid. First, boiler outlet NOx levels do not constrain achievable SCR NOx removal efficiency within the range achieved by modern

boilers, i.e., >0.15 lb/mmBtu. Rather, SCR costs increase as boiler outlet NOx decreases (i.e., as SCR inlet NOx decreases). This factor must be considered in a proper BACT cost-effectiveness analysis, but is not a technical justification for eliminating lower NOx BACT emission rates. Even if low boiler outlet NOx levels resulted in unacceptably high costs or did present a technical barrier to high SCR control efficiency (and they do not in the range relevant here), the boiler itself could be designed to achieve a higher NOx outlet level, e.g., 0.3 to 0.5 lb/mmBtu, that would allow a higher SCR NOx control efficiency, 85% to 90%, than proposed by Prairie State, 56%. A higher boiler outlet NOx, say 0.5 lb/mmBtu, would allow a lower NOx emission rate to be achieved, 0.05 lb/mmBtu assuming 90% control, at a lower annualized cost and lower cost effectiveness.

These events in the Thoroughbred proceeding are not directly relevant to the application for the proposed plant. The Illinois EPA has concluded that coal quality is not a factor that prevents design and operation of an SCR to comply with a NOx limit of 0.07 lb/mmBtu. The uncontrolled boiler NOx rate is also not a factor in the establishment of this limit. At the same time, the boiler's uncontrolled NOx emission rate would be a factor that affects the level of performance of the SCR if it were being separately considered, by itself. It certainly would not make sense to raise the uncontrolled NOx emissions of the boiler so that the cost-effectiveness of an SCR system is raised. This would not reduce the overall costs of the SCR, but would simply shift costs from one aspect of the control system to the other. This is also not a relevant consideration for the proposed boilers, as it has not been suggested that SCR systems are not an appropriate component of the control system for NOx.

139. Poor coal quality does not limit the ability of the SCR to control NOx to levels lower than 0.08 lb/mmBtu if coal quality is properly included in the design of the SCR. Coal quality affects the design and hence the cost of an SCR system, not its ability to control NOx. A number of methods are available to mitigate any adverse effects of coal quality on the performance of an SCR system. These include (1) washing the coal to reduce ash and sulfur; (2) locating the SCR downstream of the wet ESP where ash and SO_2 levels are low; (3) using sonic horns or soot blowers to keep the catalyst clean; (4) using an edge-hardened, low SO_2 to SO_3 conversion SCR catalyst; (5) using an economizer bypass for low-load operation; and (6) designing the air preheater to prevent acid condensation.

The commenter is correct that the quality of the coal used in the proposed boilers should not have enough of an effect on the design and operation of the SCR systems to prevent setting a NOx limit for the boilers that is lower than 0.08 lb/mmBtu. As a general matter, as also indirectly noted by this comment, coal quality does have an effect on the design and operation of an SCR system. This requires that a limit be set that contains an appropriate safety factor that accounts for normal variation in performance of the SCR systems when properly operated and maintained. In addition, coal quality can play a significant role in the performance of combustion techniques used on a boiler to minimize NOx emissions produced by the boiler, as certain types of coal are more amenable to low-NOx combustion. Thus coal quality does affect the balance between the boiler-based and SCR-based control of NOx for a unit and the actual NOx emission rate that is achievable.

140. The draft permit proposes a NOx BACT limit of 0.08 lb/mmBtu, 30-day average, and a 24-

hour average limit that is equivalent to 0.12 lb/mmBtu. As identified in my comment, a number of permits for pulverized coal boilers have been issued with lower limits. Also, a number of PSD applications are currently being processed in which lower limits are proposed.

This comment helped confirm the Illinois EPA's decision to set a NOx BACT limit for the coal-fired boilers in the issued permit at 0.07 lb/mmBtu, 30-day average. In particular, the comment provides the short-term BACT limits for ten projects. The BACT limit for seven of the projects is 0.07 lb/mmBtu, 30 day average. The lowest BACT limit is 0.06 lb/mmBtu, on a 24-hour average, for a proposed project that would burn low-sulfur bituminous coal. Another limit is set at 0.07 lb/mmBtu on a 24-hour average and, following revision, 0.07 lb/mmBtu, 30-day average for a permitted project that would burn low-sulfur Western bituminous coal. The limit for the final project (Longview) is set at 0.080 lb/mmBtu, 24-hour average, for a boiler burning a high sulfur (3.25% sulfur) bituminous coal.

141. In general, the shorter the averaging time, the more stringent the limit. Thus, a 24-hour 0.080 lb/mmBtu limit, as set for Longview, is more stringent than the 30-day 0.08 lb/mmBtu limit proposed for Prairie State. The ratio of the 30-day to the 24-hr maximum NOx emissions is 0.30, based on the actual NOx monitoring data that I reviewed for the ozone season. Therefore, the Longview NOx limit of 0.08 lb/mmBtu, 24-hr average, is equivalent to a limit of 0.025 lb/mmBtu, 30-day average.

The general principle stated in this comment is correct, i.e., a particular numerical limit becomes more stringent as the associated compliance time period is shortened. However, the specific relationship between time and a numerical limit should not be derived from monitoring data from actual emissions, as suggested by the comment. For example, the one project for which this commenter provided data on BACT limits, as discussed above, with limits for both a 24-hour and 30-day averaging period showed a much smaller effect on the compliance time period. In particular, the BACT limits for NOx for a project in Trimble Kentucky are 0.08 lb/mmBtu, 24-hour average, and 0.07 lb/mmBtu, 30-day average, which is identical to the NOx limits ultimately set for Longview.

As a general matter, the Illinois EPA elected to retain a BACT limit, in lb/mmBtu, for NOx (as well as SO_2) that applies on a 30-day average. This is because this time period is the most common form in which BACT limits are set for these pollutants, and is identical to the time period used by USEPA for NOx and SO_2 emission standards in the NSPS for utility boilers. It also reduces the magnitude of the safety factor that is otherwise needed if limits are set on a daily basis.

142. The draft permit proposes a limit for NOx on a 24-hour average basis that is equivalent to 0.12 lb/mmBtu. Permits for pulverized coal boilers have been issued with BACT limits that are lower than this. Also, PSD applications are currently being processed in which lower limits are proposed.

The limit addressed by this comment is not a BACT limit. Rather it is a statement of the permitted emissions of NOx from the proposed plant on a daily basis. It is included in the

permit to facilitate future assessments of air quality that involve the proposed plant, including evaluation of its potential effects on the Mingo Wilderness area.

143. Coal quality, while important in the design of an SCR is generally taken into consideration in the cost-effectiveness analysis. The high sulfur, high ash bituminous coal to be used at the proposed plant should not limit the achievable NOx limit, compared to low sulfur, low ash sub-bituminous coal. Coal quality presents challenges for both types of coal.

High sulfur content can be designed for by using an SCR catalyst with a low SO_2 to SO_3 conversion rate. Catalysts with a conversion rate as low as 0.1% are commercially available. The high ash content can be designed for by using an erosion-resistant catalyst with a large pitch, coupled with sonic horns or soot blowers to keep the catalyst face clean. Alternatively, the coal can be washed to remove >80% of the ash and >20% of the sulfur. These design features would increase the cost of an SCR for the high sulfur, high ash case, compared to an equivalent low sulfur, low ash coal. However, low sulfur, low ash subbituminous coals have another, unique set of quality issues, namely catalyst poisoning by alkaline metals such as calcium and sodium, which must also be considered in the design of the SCR and which also add to the cost of a SCR system.

While these observations about SCR catalysts for high sulfur coal applications are correct, they are not necessarily desirable. In particular, to facilitate collection of mercury, as well as maximize boiler efficiency, a lower-temperature catalyst with high oxidizing potential may be desirable.

144. The NSR Manual indicates that other sources of information should be considered in setting BACT limits, including foreign experience, lower polluting processes, innovative technologies; vendor information; and journal articles, among others. (NSR Manual, pp. B.5, B.11 – 14.) The Illinois EPA file suggests that these other sources were not thoroughly considered, and in some cases, not at all. These other sources indicate that BACT for NOx is lower than the proposed limit of 0.08 lb/mmBtu. Some of this available information is reviewed below. However, this is only a partial listing. Illinois EPA should require that the applicant, the largest coal company in the world with access to information on other coal facilities, conduct a thorough research of all pertinent sources of BACT information.

Prairie State has reviewed "other sources of information," as documented by the supplemental material that it has submitted for the application. The Illinois EPA has also reviewed other information about control technology for NOx emissions. Both reviews are memorialized within a voluminous administrative record assembled by the Illinois EPA and, as related to this comment, are evidenced by responses to similar comments throughout this section.

145. Several plants outside of the U.S. have achieved lower NOx emission limits. The 250 MW Amager plant in Denmark is achieving NOx levels of less than 0.04 lb/mmBtu. This plant

started up in October 2000 and was designed for 2.5% sulfur coal. Several units are operating at low NOx levels in Japan. An SCR unit on a 1000-MW boiler in Japan has achieved a NOx rate of 0.05 lb/mmBtu. A 250-MW boiler has achieved a NOx emission rate of 0.04 lb/mmBtu, based on 80% NOx control.

These comments generally confirm that SCR is a very effective means to control NOx emissions and the appropriate control technology associated with the BACT determination.

146. The USEPA, in preparing for various rule makings, has identified a number of coal-fired units that have met lower NOx rates than proposed for this plant. These include three circulating fluidized bed units meeting a NOx rate of 0.03 lb/mmBtu; a Swedish unit meeting 0.07 lb/mmBtu; and a US unit meeting 0.07 lb/mmBtu.

The fact that certain units achieve lower emission rates in actual practice does not demonstrate that an enforceable limit should be set at such levels. This is shown by the fact that the USEPA has not proposed regulations that are based on limits that are identical to the emission rates that are achieved by the particular units cited in these comments.

147. There are a number of innovative control systems and other control methods that were not considered in the application and should be. These include the Pahlman process, the ECO Multi-Pollutant Control Technology, ROFA and ROTAMIX, combustion optimization systems, and ultra low-NOx burners, which are able to achieve boiler outlet NOx levels of 0.15 lb/mmBtu.

Innovative control systems are not appropriate for consideration as BACT unless they have progressed beyond the pilot or feasibility demonstration stage. BACT requires a control technology that can reliably achieve the particular limit(s) that are then set for the performance of the technology. As noted in the NSR Manual, it is not necessary to evaluate innovative technology, which is still undergoing basic development and has not been demonstrated on identical or similar units. In addition, a 1,500 MW power plant is not the appropriate context in which to evaluate innovative control technologies, particularly as demonstrated technologies are available. Such a plant, given the magnitude of uncontrolled emissions, its critical role in providing electricity, and the scale of the financial investment, must rely upon a technology that is continually viable and that avoids potential risks and/or delays that might otherwise accompany pilot projects.

148. Higher NOx removal efficiencies are achievable by SCR systems. BACT is an "emissions limitation… based on the *maximum degree of reduction* for each pollutant…" A top-down analysis requires that the control effectiveness, *i.e.*, percent pollutant removed, be identified. (NSR Manual, p. B.6.) The Prairie State file does not reveal the assumed NOx control efficiency for the SCR system. Thus, it is not possible to determine if the proposed emission limit represents the "maximum degree of reduction" for NOx, as is required by the plain language of the definition of BACT. Therefore, the BACT analysis for NOx is incomplete and inadequate.

The overall performance of the control measures for NOx was provided in the application.

The application also contained information on the uncontrolled emission rate achieved by the boiler. In addition, further detailed consideration of "boiler control" and "SCR control" was not required because of the interactive nature of these techniques and the nature of emission data for existing units. In particular, the emission data collected for SCR systems does not distinguish between the amount of control provided by low-NOx combustion techniques and by the SCR, but simply reports on the overall emission rates that are being achieved.

149. The Thoroughbred Generating Company has proposed the essentially identical Thoroughbred plant near Central City, Kentucky. The NOx limit of that plant is also 0.08 lb/mmBtu. This is based on 56% SCR control efficiency, as disclosed during testimony during the permit appeal proceeding for the Thoroughbred plant. This is a very low NOx control efficiency. Today, most SCR systems are designed to achieve a NOx removal efficiency of 80% to 90%. Presumably, the 0.08 lb/mmBtu limit for the proposed plant is also based on the same low SCR control efficiency.

The Illinois EPA would agree that 56 percent control would be low for the SCR systems, <u>if</u> the uncontrolled NOx emission rate from the Thoroughbred boilers would always be no more than 0.18 lb/mmBtu, as implied by this comment. Perhaps this represents unique aspects of this project or the boiler supplier has chosen to emphasize the low-NOx characteristics of the boiler design, knowing that add-on SCR systems will also be present to make up for any deficiencies in actual performance. In any event, as a general matter, the Illinois EPA believes that 0.18 lb NOx /mmBtu, 30-day average, is unrealistic for a limit on "uncontrolled" emission for boilers burning Midwestern bituminous coal. A more realistic limit is in the range of 0.4 or 0.5 lb/mmBtu. This yields a SCR control efficiency that is in the range of 80 to 85 percent.

150. For a technology such as SCR, which is capable of achieving a wide range of performance levels, "it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise." The Prairie State file contains no justification for the control efficiency that the NOx BACT level is based on. Assuming that the NOx limit of 0.08 lb/mmBtu is based on a 56% control efficiency, a much lower NOx emission limit, 0.02 lb/mmBtu, corresponding to a 90% reduction of boiler outlet NOx of 0.18 lb/mmBtu, should have been evaluated in the BACT analysis.

This comment inappropriately focuses on the performance of SCR simply in terms of control efficiency, rather than as a pair of values, i.e., uncontrolled "boiler" NOx emission rate and control efficiency. While SCR is generally recognized as being able to achieve a nominal 90 percent control efficiency, this is under optimal conditions for control of NOx, e.g., cyclone fired boilers where the boiler emission rate is high or on natural fired turbines, where the exhaust is not laden with ash.

151. The proposed NOx limit for the Prairie State permit is too high. Based upon recent experience, the limit should be 0.04 to 0.05 lb/mmBtu. Over the past two years, plants have installed SCRs to reduce NOx emissions "summer" ozone season. Most of these SCRs have been operated only seasonally, but they could operate year-round if required to do. Data is

available on the actual NOx emissions of 17 such units in the 2003 ozone season. Six of units achieved 0.05 lb/mmBtu and another four achieved .04 lb/mmBtu. Based upon this data, the BACT limit for the proposed plant should be 0.05 lb/mmBtu or less. Such a limit would be consistent with recent applications for new coal-fired boilers, including the 750 MW pulverized coal unit proposed by City Public Service in San Antonio, Texas, which proposes a limit of 0.05 lb/mmBtu.

The recent experience with SCRs cited in this comment is not an adequate basis to set a limit for NOx that is as low as recommended by the comment. First, the emission data reflects a block quarterly average, not a 30-day rolling average, which is the format in which the NOx limit for the boilers is being set, for consistency with the NSPS and the limits set for other boilers. Second, the emission data likely reflects the performance of new SCRs and is also influenced by the role of the NOx SIP Call/Trading Program, as it is an incentive to minimize NOx emissions. Because the performance of SCRs is affected by the condition of their catalyst, data on initial operation does not adequately address the long-term performance of the catalyst, including the period immediately prior to overhaul and replacement of bed(s) of catalyst. In addition, it appears that the limits actually proposed by City Public Service for Unit 2 at its Spruce plant provide support for the NOx limit being set for the proposed plant. In particular, while City Public Service has proposed a NOx emission limit of 0.05 lb/mmBtu on an annual basis, the limit proposed on a 30-day rolling average basis is 0.069 lb/mmBtu. This is essentially identical to the 0.07 lb/mmBtu limit being set for the proposed plant, considering that that unit is being designed for Powder River Basin coal, a high moisture fuel for which low-NOx combustion techniques are especially effective.

152. USEPA has explained that reliance on "average performance" for BACT is inappropriate. BACT requires "best" and the average of other recently permitted plants is not determinative. Accordingly, the proposed NOx limit, 0.08 lb/mmBTU, 30-day average, does not represent BACT because Prairie State indicates this limit is equivalent to the average performance of other power plants. This comment also applies to the other BACT limits discussed in my comments:

This comment accurately reflects this aspect of the legal definition of BACT, as confirmed by USEPA. However, BACT for the proposed plant has not been set as the average of either the actual performance or emission limits of other power plants.

As explained elsewhere, the level of performance is based upon recently issued permits for new power plants in other states and the format of the limit, i.e., 30-day rolling average, was selected so as to be consistent with the NSPS for power plant boilers, i.e., 40 CFR 60, Subpart Da.

153. David Shultz, USEPA Region 5, in his personal capacity, submitted comments on USEPA's proposed Interstate Air Quality Rule in which he expressed his views that: "…well over 100 SCR's have been installed in recent years, with many more under construction, and SCR's have demonstrated NOx levels below 0.05 lb/mmBtu …" As the senior utility expert at USEPA Region 5, Mr. Shultz's views should be accorded significant weight.

In these comments, Mr. Schultz was addressing the "design" emission rate for NOx that should be the basis of new, comprehensive, national regulations for power plants then proposed by USEPA as they would address emissions of NOx. Mr. Schultz was not commenting on BACT for a particular plant. In this now final federal program, individual boilers would not be required to comply with any new emission limits for NOx. Instead, the design emission rate, as addressed by Mr. Schultz, would determine the allocation of annual NOx allowances to individual sources. Individual sources would then buy or sell allowances depending upon whether their actual NOx emissions were such that they ended up with a deficit or surplus of NOx allowances for the year. Effectively, this means that affected sources only have to meet with the design limit for NOx in aggregate, as an average, emission rate, over a multi-state region that extends over most of the eastern United States. In addition, the NOx emissions of individual affected sources would be determined on a calendar year and a seasonal basis, significantly longer time periods than the 30 day rolling average compliance period that accompanies the BACT limit for NOx emissions for the coal-fired boulers at the proposed plant. Accordingly, this program poses issues for affected sources about the likely cost of compliance. The program does not pose concerns for noncompliance, as posed when BACT emission limit(s) are being set. The concerns posed by noncompliance involve not only the cost of compliance, but also penalty costs, legal costs, and various costs associated with uncertainty, ultimately including a potential risk that a source will not be able to economically continue in operation.

154. In addition to the plants that are currently meeting NOx emission rates that are lower than proposed for Prairie State, vendors have offered guarantees to many other plants to comply with their NOx SIP Call obligations. Most of these guarantees have been offered for a NOx removal efficiency of 85% to 90% and a NOx emission rate that is substantially lower than proposed for Prairie State. These include the following guarantees for NOx removal: (1) 95% removal to achieve 0.04 lb/mmBtu for the 675 MW boilers at each of Allegheny's Harrison and Pleasants Stations in West Virginia; (2) 90% removal to achieve 0.042 lb/mmBtu at the 160 MW boiler at AES Cayuga Unit 1; (3) 90% removal to achieve 0.05 lb/mmBtu at the 675 MW boiler at AES Somerset; and (5) 83% removal to achieve 0.05 lb/mmBtu at the 585 MW boiler at East Kentucky Power's Spurlock Unit 3. These units have not historically met their vendor guarantees due to operational decisions by their owners. However, they are expected to operate at near their guaranteed NOx rates as necessary to comply with the NOx SIP Call, commencing during the 2004 ozone season.

Vendor guarantees for SCRs, which involve "demonstrated performance" under specified operating conditions as related to transfer and acceptance of an SCR system from the vendor to the source cannot be treated as long-term performance guarantees for the SCR. While such performance levels can be demonstrated during specified operating conditions when an SCR is new, this does not demonstrate that such limits are achievable on a long-term basis.

More generally, this information generally provides further confirmation that a BACT limit for NOx set at 0.07 lb/mmBtu is appropriate. This is because of the difference in the circumstances of a "limit" under the NOx Trading Program and a limit under the regulatory PSD program. NOx emission rate of 0.05 lb/mmBtu may certainly be an appropriate target for operation under a cap and trade program for NOx emissions, which addresses NOx

emissions on a seasonal basis, with provision for trading of allowances so that failure of a unit to meet this emission rate would not result in noncompliance. In contrast, a BACT limit would apply on both a shorter and more-frequent time period, i.e., a 30-day rolling average. Failure to comply with a BACT limit is grounds for enforcement and penalties. Accordingly, the fact that sources are targeting operation of SCRs on a seasonal basis for a NOx emission rate in the range of 0.04 to 0.05 lb/mmBtu, provides further support that is appropriate that a BACT limit be set higher, i.e., at 0.07 lb/mmBtu.

155. The recently settled lawsuit challenging the Longview plant resulted in an agreement to establish a NOx limit of 0.07 lbs/mmBtu, 30-day average and 0.065 lbs/mmBtu, annual average.

This development contributed to the Illinois EPA's decision to set the BACT limit for NOx at 0.07 lb/mmBtu.

156. The BACT analysis fails to properly rank BACT options and select BACT. A plant using IGCC technology would have less total emissions, including emissions of NOx when compared to the 0.08 lb/mmBtu limit proposed for the plant..

The differences in emissions between IGCC and boiler technology are only one aspect of the evaluation of IGCC technology. The PSD rules do not contemplate a BACT determination that as a consequence of the selection of the BACT control technology would prevent proposed plants from being developed. Rather, BACT represents the maximum degree of emission reduction that is achievable for proposed projects.

BACT – Particulate Matter

157. High sulfur coal is bad for baghouses, but baghouses are proposed for the non-combustion processes at the plant. Why would baghouses be effective there, but not for combustion?

The exhaust from units other than the boilers is only contaminated with dust, which baghouses can readily control. However, for the boilers, baghouses would also have to withstand corrosive attack from sulfuric acid mist (H_2SO_4) contained in the exhaust. The sulfuric acid mist is formed when SO_3 combines with the water vapor (H_2O) that is also present in the flue gas. If this mist then condenses out of the flue gases and becomes liquid, the droplets are highly corrosive and cause accelerated deterioration of the filter bags and internal components of the baghouse, destroying the integrity of the filter system. Because collected ash or cake on the bags in a baghouse must be removed on a regular basis, by sending clean air "backwards" through the bags, opposite to the direction of normal gas flow, some cooling that could cause condensation cannot be avoided in a baghouse. For high sulfur coal, even if washed, the levels of SO_3 are such that cooling is sufficient to cause condensation and lead to corrosion. For low-sulfur coal, the levels of SO_3 are lower and the dew point is lower so the cooling generally is not sufficient to cause condensation and the gradual damage to the system is not significant. In addition, the various measures that can be used inside the boiler to absorb SO_3 and protect against corrosion are more effective.

Acid corrosion is not as critical for ESPs. The ESPs on coal-fired boilers can be operated at constant temperatures so are at less risk for condensation than baghouses. ESPs are also more robust systems, as they do not rely upon maintaining the integrity of a barrier separating dirty flue gas from clean air. Instead, ESPs use electrostatic attraction to pull particles of ash out of the flue gas, so that the flue gas becomes progressively cleaner as it passes through the ESP. Accordingly, the selection of an ESP for control of particulate matter from the proposed boilers is appropriate, as ESPs will be both reliable and highly efficient. However, as SO_3 is present in the flue gas and will be exposed to water in the SO_2 scrubbers, which follow the ESPs in the control train, the scrubbers must be followed by wet ESPs. Wet ESPs are highly effective in controlling sulfuric acid mist, which occurs as fine droplets. Wet ESPs can also be protected from corrosion because wet ESPs are designed to operate "wet." The water sprays, which are the first step in the device, are maintained at an alkaline pH, so as to immediately neutralize collected sulfuric acid mist and protect internal surfaces.

158. BACT was not required for particulate matter (PM). The proposed filterable PM limit is not BACT for this plant.

The emission limit being set for filterable particulate matter for BACT for the coal-fired boilers represents the maximum degree of reduction, with an appropriate safety factor to accommodate normal variation in performance when the control system is properly operated and maintained. The safety factors associated with limits for PM emissions must be significantly larger, in relative terms, than those associated with the limits set for emissions of SO_2 and NOx. This is a consequence of the nature of particulate control systems, the very high levels of control that must be achieved, the resulting low levels of emissions and the use of short-term testing to confirm compliance. The circumstances for SO_2 and NOx emissions are generally different, particularly as compliance is determined by continuous emissions monitoring on a 30-day rolling average basis.

159. The permit should include a limit for total PM10, which includes both filterable and condensable PM10 emissions. The draft permit only contains a limit for filterable PM10 emissions. In the draft permit, the Illinois EPA addresses condensable PM emissions by claiming that a limit on emissions of sulfuric acid mist would serve "as a surrogate" for control of condensable PM emissions. USEPA has taken the position that condensable PM is part of a source's PM emissions and must be considered in determining BACT and in conducting air quality analyses.

In response to this comment from USEPA, Region 5, a BACT limit for total PM10 has been included in the issued permit for the coal-fired boilers. The limit is 0.035 lb/mmBtu, with a provision that the BACT limit may be lowered by the Illinois EPA based on the demonstrated performance of the boilers and their control systems for total PM10 including condensable particulate matter.

160. The proposed testing for condensable PM/PM10 is not adequate to develop a limit, or determine compliance if a limit were developed and incorporated into the Permit. The draft Permit requires an initial source test, a subsequent source test 9 to 15 months later, and

thereafter, every 36 months, unless two consecutive PM tests are less than 0.01 lb/mmBtu, in which case the testing drops to once every 54 months. (Condition 2.1.8.) BACT emission limits must be met on a "continual basis." (NSR Manual at B.56.) Infrequent testing at long intervals is not adequate to demonstrate continuous compliance.

As well as including a limit for total PM10, the issued permit also includes requirements for additional testing of PM10 emissions to support the evaluation of total PM10 emissions and the establishment of a lower limit based on actual data. For this purpose, at least five tests must be conducted during the course of the initial three years of operation. If the evaluation period is extended for an additional year, at least two more tests must be performed.

Provisions in the permit addressing the maximum interval between subsequent PM tests have been reworked to address limits for both PM and total PM10, including condensables. To qualify for the longer interval between tests, the measured emissions must be no more than two thirds of both limits. In addition, the maximum intervals between tests are now set at 30 months and 48 months, if measured emissions are no more than two thirds of the applicable limits.

As a general matter, the provisions of the permit for particulate matter are adequate. Periodic emissions testing is accompanied by compliance assurance monitoring for filterable particulate matter, which requires Prairie State to develop and maintain documents that formally define the relationship between monitored data and particulate matter emissions, as provided by 40 CFR Part 64. It is possible that this work will demonstrate that the required continuous monitoring provides data that is reliable and precise enough to be used to directly assess compliance with the established limit given the specific circumstances presented by the proposed boilers, i.e., a high moisture exhaust following a scrubber and wet ESP and a limit set at 0.015 lb/million Btu heat input. In this regard, the compliance procedures set in the issued permit, which is a construction permit, are more appropriately considered to be the "basic" compliance procedures. This is because they may be supplemented based on actual experience during the periodic processing of the operating permit for the plant.

161. "Manual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source." (40 FR 46241 10/6/75.) A widely used handbook on monitoring notes, with respect to PM10 testing, that: "Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests." Accordingly, where feasible, continuous emission monitoring systems should be required.

The Illinois EPA agrees with the final sentiment expressed in this comment as applied to particulate emissions from the coal-fired boilers, i.e., where feasible, continuous monitoring should be required. It is for this reason that the permit requires use of continuous emissions monitoring systems as a compliance assurance method for particulate matter.

However, with respect to manual stack tests, this comment overlooks key aspects of such tests that serve to compensate for the short-comings that are noted. First, stack tests are conducted

under operating conditions of emission units that place the greatest challenge on the control system. This typically includes operation at or near capacity. For ESPs this results in the lowest efficiency (highest emissions), since the residence time of flue gas in the ESP is lowest and there is less time to extract particles from the gas stream. Second, stack tests have two functions. In addition to confirming compliance, stack tests also should establish the levels of operating parameters to which a source is generally held. Thus, if a source "optimizes" performance of its control system during testing, the source should be expected to continue operating with an optimized control system. If the source deviates from optimized operation, it should restore optimized performance or retest to demonstrate compliance at the conditions at which it now intends to operate. It is in part for this reason that the Illinois EPA has not set a BACT limit for opacity from the coal-fired boilers, as doing so, could establish an expectation that monitored opacity within such limit is indicative of compliance with the limit for particulate matter, for which opacity is a surrogate.

162. The proposed filterable PM/PM10 limit is not BACT. For filterable PM/PM10, the Illinois EPA proposed a limit of 0.015 lb/mmBtu, but did not indicate the basis for this choice. The applicant's BACT analysis reported a proposed filterable PM/PM10 emission limit of 0.012 lb/mmBtu (App., Table C.5-2, p. C-25), but did not explain why this limit was not selected as BACT, beyond characterizing it as proposed. Lower PM/PM10 emission rates have been permitted and achieved. These lower PM/PM10 rates should have been evaluated in the BACT analysis. The National Park Service has compiled PM10 emission rates for proposed, permitted, and operating coal-fired power plants. This list shows that there are four coal-fired power plants that are proposed, permitted, and/or currently meeting lower PM/PM10 limits than proposed, with limits ranging from 0.011 to 0.012 lb/mmBtu. Prairie State reported some of these in its "BACT Summary Table," but did not evaluate them in its BACT analysis. The BACT analysis should be revised to include an analysis of these lower limits. The revised analysis should either accept the lower emission rates as BACT for PM/PM10 or explain why these emission rates are not BACT, based on physical and chemical differences in the flue gases or an economic, energy, and environmental analysis.

Prairie State rejected a limit of 0.012 cited in these comments because it was a proposed limit. The Illinois EPA rejected this limit and other limits cited in this comment based on the lack of an adequate margin of safety to assure compliance. Continuous emissions monitoring systems for particulate matter will also be used on the coal-fired boilers. Even if these systems are only used for compliance assurance monitoring, they will potentially increase the rigor of the PM emission limit set for the boilers.

163. Compliance with PM/PM10 permit limits is normally demonstrated by performance testing. The NSR Manual indicates that performance tests are one of the sources that should be considered in identifying control technology alternatives. (NSR Manual, p. B.11.) Prairie State did not evaluate any performance tests. Performance tests from a number of sources indicate that coal-fired boilers routinely meet much lower PM/PM10 rates than proposed for this plant. The State of Florida enters performance tests into an electronic database. The Florida database contained results from 225 tests of PM/PM10 tests for coal-fired power plants that showed PM or PM10 at less than 0.015 lb/mmBtu, the proposed limit. Of these, 147 (65%) showed emissions less than 0.01 lb/mmBtu and 82 (36%) showed emissions less

than 0.005 lb/mmBtu. (Ex. 21.53)

This comment reflects a selective presentation of the available data from Florida. It only reports on test results that are less than 0.015 lb/mmBtu and disregards test results that are higher than 0.015 lb/mmBtu. Considered more broadly, the extensive database of test results from Florida confirms significant variability in the tested PM/PM10 emissions of power plants, with measured emissions that are often below the applicable limit by a very large factor of safety. For example, test data for the two units at St. Johns River Power Park, which are subject to a limit of 0.03 lb/mmBtu, consistently show test results less than 0.015 lb/mmBtu (11 tests for Unit 1 ranging from 0.0028 to 0.01 lb/mmBtu and 10 tests for Unit 2 ranging from 0.0004 to 0.0081 lb/mmBtu). However, both units have experienced test results greater than 0.015 lb/mmBtu (two tests at Unit 1 at 0.016 and one test at Unit 2 at 0.0211). Similar results are found for the Stanton Energy Center in Orlando.

164. Results similar to those in Florida have been reported for coal-fired power plants in other states. Several of Georgia Power's equipped with ESPs have achieved lower filterable PM/PM10 rates, including: Scherer Unit 3, 0.010 in 1998; and 0.011 in 2000; Scherer Unit 4, 0.003 lb/mmBtu in 1998 and 0.004 lb/mmBtu in 2000, Yates Unit 7, 0.006 lb/mmBtu; Yates Unit 6, 0.008 lb/mmBtu; and Hammond Unit 4, 0.008 lb/mmBtu.

This information is of less relevance than the data from Florida, also provided by this commenter, as it reports on the results of selected tests of particular boilers. Data from other tests confirms variability in performance. In particular, when the Scherer plant, which is subject to a limit of 0.1 lb/mmBtu, was recently tested in 2004, the measured emissions were 0.0123 and 0.0083 lb/mmBtu, respectively. In 2003, the measured emissions of Yates Units 6 and 7, which are subject to a limit of 0.24 lb/mmBtu, were both 0.017 lb/mmBtu. In 2002, the emissions of Hammond Unit 4, also subject to 0.24 lb/mmbtu, were 0.016 lb/mmBtu.

165. A recent article also reported four performance tests for coal-fired power plants in New Jersey and Utah that ranged from 0.0045 lb/mmBtu to 0.0126 lb/mmBtu. (Ex. 22: Corio and Sherwell 2000.58)

As already explained, individual tests do not provide an adequate basis to set BACT for filterable PM10 as they do not address normal variability in the performance of a boiler and its control system for particulate. Incidentally, this article is also of interest as it reports on the total PM10 emissions (filterable and condensable) for the selected power plants. In particular, for L.P. Cogen, Mercer 1, and Mercer 2 in New Jersey, the article reports total PM10 emissions of 0.0253, 0.0499 and 0.0648 lb/mmBtu, respectively. For only one plant, Bonanza power in Utah, which burns local western coal, does the article report a total PM10 emission rate, 0.0163 lb/mmBtu, that is less than 0.018 lb/mmBtu.

166. The low PM/PM10 rates measured in Florida, Georgia, etc., are consistent with the BACT determination made by Matt Haber in the Baldwin lawsuit. In that case, Mr. Haber found that BACT for filterable PM as of 2002 for Units 1 and 2 was 0.006 lb/mmBtu, achieved with a baghouse.

The BACT limit for PM emissions recommended by Mr. Haber is significantly lower than the limits for PM being required of other new boilers, to a degree that is unrealistic. The recommended limit reflects ideal performance of the PM control devices (baghouses in this case, as low-sulfur coal is the designated coal supply for the boilers), without any safety factor. It is also significant that the recommendation reflects a calculation of control efficiency for the baghouses, whereas the performance of filter-type control devices is more appropriately addressed, from a technical perspective, in terms of the outlet dust loading that is achievable. A more telling piece of information from this lawsuit is the level of PM emissions being required of the boilers at Baldwin under the Settlement Agreement, i.e., 0.015 lb/million Btu, as filterable PM emissions, as measured by USEPA Method 5.

167. Much lower PM/PM10 rates have been achieved than the 0.015 lb/mmBtu proposed as the BACT limit in the draft permit. The BACT analysis should be revised to explicitly evaluate a much lower PM/PM10 filterable rate.

The low PM/PM10 emission rates achieved in practice in certain tests are not a sufficient basis to set the BACT limit for PM/PM10 emissions, as they do not provide the necessary safety factor that must be associated with an emission limit. For PM/PM10, in particular, the emission limits set in permits for other plants, or even proposed in the applications for new plants, are more useful as they reflect consideration of normal variation in performance.

168. The total PM/PM10 limit in the draft permit is not BACT. The total PM/PM10 limit proposed in the BACT analysis and draft permit is 0.05 lb/mmBtu, comprising 0.015 lb/mmBtu filterable and 0.035 lb/mmBtu condensable is not BACT.

The Illinois EPA must agree with this comment, as the draft permit did not set a BACT limit for total PM10. An emission rate of 0.05 lb/mmBtu was used as the permitted emission rate for PM10 for purposes of the air quality analyses. The draft permit addressed filterable PM with its own BACT limit (0.015 lb/mmBtu). It separately addressed condensable PM, using sulfuric acid mist as a surrogate, with a limit of 0.005 lb/mmBtu. The issued permit still contains these BACT limits from the draft permit. It also contains a BACT limit for total PM, 0.035 lb/mmBtu, which is subject to further evaluation and lowering based on actual performance data. This further evaluation is an essential component of the BACT determination for total PM/PM10 emissions. It is necessitated by the current state of scientific knowledge about condensable particulate emissions, total PM10 emissions, and their control.

169. In 2002, for Baldwin Units 1 and 2, Matt Haber of USEPA recommended a BACT limit for PM of 0.006 lb/mmBtu based on use of a 99.6% efficient baghouse, with compliance to be determined by periodic testing and triboelectric "broken bag" monitors. His analysis was based, in part, on the cost-effectiveness finding from Public Service Electric & Gas's Mercer Unit built in 1994 that included a $38.9 million ESP achieving 99.8 % efficiency.

As noted in the comment, the compliance procedures recommended by Mr. Haber are similar to those associated with the BACT determination for PM emissions being made for the coal-fired boilers at the proposed plant.

170. In the application for Indeck-Elwood, Indeck noted four plants with emission limits for filterable PM10 that were less than 0.015 lb/mmBtu: 0.0088 lb/mmBtu, Northampton Generating Station, Pennsylvania; 0.010 lb/mmBtu, Reliant Energy - Seward, Pennsylvania; and 0.011 lb/mmBtu, York Energy, Pennsylvania and JEA Northside, Florida.

The limits for these plants are not directly transferable to the proposed coal-fired boilers because of the use of continuous particulate matter monitoring, as previously explained. In addition, there may be circumstances present for these circulating fluidized bed boilers, which are equipped with baghouses and burn waste coal or coal and petroleum coke in the case of JEA, that have resulted in the establishment of these particular limits.

171. USEPA recently wrote in comments on the proposed Longview plant in West Virginia that even more stringent PM limits must be considered in a PM BACT analysis based on performance testing at Northampton Generating plant in Pennsylvania, which indicate an even lower PM rate. According to USEPA, based on recent performance testing (for both filterable and condensable), Northampton is achieving a PM limit of 0.0045 lb/mmBtu.

The comment was investigated by West Virginia. It found that testing of the Northampton boiler did not include measurements for condensable particulate as indicated by USEPA. In evaluating this small 110 MW power plant burning coal waste, West Virginia also did not find it to be an appropriate basis to set a BACT limit for PM/PM10 emissions, instead setting a limit of 0.018 lb/mmBtu on total PM/PM10 emissions. This is the "default" limit for BACT for total PM/PM10 emissions for the proposed coal-fired boilers if Prairie State elects not to perform or fails to complete an evaluation of PM/PM10 emissions.

172. The BACT analysis for PM must consider the additional, significant mercury reductions associated with using baghouses, instead of ESPs. As USEPA's Information Collection Request found, coal-fired boilers with baghouses consistently achieved a significantly higher mercury control. The Illinois EPA may not simply rely on the averages of other recently permitted coal boilers.

The case-by-case determination of MACT for mercury emissions from the coal-fired boilers addresses emissions of mercury directly, by requiring that emissions either be effectively controlled by "co-benefit" with the basic control train or by the control train supplemented with sorbent injection specifically for control of mercury. This approach is more effective than dictating use of baghouses. Baghouses would not provide effective, reliable control of either particulate matter, or mercury, as effective control of mercury by a baghouse depends upon collection of particulate that has absorbed the mercury.

173. The permit must include an opacity limit that constitutes BACT. The definition of BACT at 40 CFR 52.21(b)(12) clearly provides that BACT shall include a visible emissions standard. The 20 percent opacity limit of the NSPS, 40 CFR 60 Subpart Da, which applies to the coal-fired boilers, does not reflect the maximum degree of reduction for the particulate that will be emitted by the boilers. Not only is an opacity limit required as part of the BACT determination, but a limit is needed that correlates with the PM10 limit and reflects almost

100% removal of PM emissions.

The language in 40 CFR 52.21(b)(12) being addressed by this comment is contained within parentheses. The question therefore is whether the language requires an opacity limit to be set as BACT or allows an opacity limit to be set as BACT. The comment not does provide any discussion to support the former position. The Illinois EPA believes that the latter position is appropriate. The definition of BACT in the Clean Air Act does not include the parenthetical phrase in question. It simply states that BACT is an emission limitation for each pollutant subject to regulation. Since opacity is not a pollutant, there is not a statutory obligation to set an opacity limit. The enhancement to the regulatory definition by USEPA must be construed as a clarifying action on its part to indicate that it is acceptable to set opacity limits as part of BACT. Moreover, the comment did not recommend a specific opacity limit that would be appropriate as BACT.

Incidentally, the Illinois EPA does agree with this comment as it indicates that the opacity limit set by the applicable NSPS does not reflect BACT. However, the identification of a level of opacity that correlates with the PM emission limit is best done in conjunction with actual emission testing for PM. The circumstances are similar to those of the continuous particulate matter monitoring systems required on the coal-fired boilers, for which actual PM testing must also be performed to establish a correlation curve between the output of the monitoring system and the rate of particulate emissions.

174. The permit should require PM10 continuous emissions monitoring systems (CEMS). Such CEMS are being installed at power plants subject to NSR settlements and offer the most effective method to ensure continuous compliance with PM10 standards.

These systems are required to be installed and operated on the coal-fired boilers (refer to Condition 2.1.10(d) of the draft and issued permits). However, these systems are to be used for the purpose of compliance assurance monitoring. This is because of the limited experience with such monitoring systems, especially for boilers with high-efficiency SO_2 scrubbers and high-moisture levels in the stacks. This will likely prevent use of PM continuous monitoring systems that rely on optical principles to quantify the level of PM in the exhaust. It also means that significant uncertainty may be inherent in the correlation curve(s) developed with the system that is selected. This will certainly be the case if condensable PM is converted into filterable PM in the monitoring system, so that the systems measure more than filterable PM.

175. The permit should include a minimum of annual tests for particulate matter, using USEPA Methods 5, 201 or 201A, and 202, to determine compliance.

The issued permit requires more frequent testing than would have been required by the draft permit, as such testing is needed to evaluate total PM10 emissions. However, it is inappropriate for the construction permit to broadly require particulate matter testing of the coal-fired boilers on an annual basis. The construction permit will be followed by operating permits pursuant to Title V of the federal Clean Air Act, which will address the ongoing operation of the facility. A better informed decision can be made on the frequency of particulate matter emission tests during the issuance and periodic renewal of these operating

permits, as the frequency of testing can be set based on the actual results of testing that has been conducted, opacity monitoring data, and the demonstrated functionality of the continuous emissions monitoring system for particulate matter. The hope is that the continuous emissions monitoring system will prove very effective as a tool to help assure compliance, reducing the frequency of stack tests. It is also important to consider the role that more refined provisions for testing, in which the frequency of testing is based on test results, could have as an incentive for the plant to minimize particulate matter emissions.

176. Although the Illinois EPA proposed to regulate condensable PM using sulfuric acid mist as a surrogate "because of the limited data that is available on the rates of condensable emissions from pulverized coal boilers, especially new boilers burning Illinois coal which are equipped with high-efficiency SCRs," it is not clear that the draft permit would actually accomplish this. This is because the only identification of the condensable PM10 emissions of the boiler is in a note to Table I, which lists the permitted emissions of the coal-fired boilers. This note states, "…the emission rate for condensable particulate matter was conservatively estimated to be 0.035 lb/mmBtu." However, the permit itself does not require that this limit be met, i.e., there is no condition specifying a condensable PM/PM10 limit. Indeed, elsewhere, the draft permit indicates, "…testing of condensable particulate emissions is required even though an emission limit is not set for condensable particulate emissions, for purposes of developing emissions data." The permit also does not state that sulfuric acid mist is being used as a surrogate for condensable PM, nor does it set out a procedure for doing so or state that a violation of the limit for the surrogate pollutant constitutes a violation of the primary pollutant. In summary, the draft permit does not contain an enforceable limit for condensable PM/PM10 or a requirement that such a limit be developed.

As limits for total PM10 (filterable and condensable) are set in the draft permit, the deficiencies noted in these comments have been corrected or are no longer a concern. They resulted from a concern that it was inappropriate to set limits based on the "place holder" value for total PM10 used in the air quality modeling, 0.05 lb/mmBtu. It is for this reason that the BACT limit for total PM/PM10 in the issued permit is set at 0.035 lb/mmBtu, to specifically account for some reduction in condensable PM10 emissions being provided by the wet ESP. Only the reduction in sulfuric acid mist by the wet ESP was considered for the purpose of this adjustment, with sulfuric acid mist assumed to constitute half of the condensable PM10 emissions. This reduces the original value for total PM10 emissions from 0.05 to 0.035 lb/mmBtu. (0.05 - ((0.05-0.15) x ½ x 0.98)) = 0.03285, ≈ 0.035). As already explained, the issued permit requires an evaluation of the total PM/PM10 emissions from the boilers based on actual test data, with provision for a lower limit to be set based on actual performance.

177. The Illinois EPA must set a BACT limit for condensable PM because it can be "effectively controlled." In addition to its "filterable" component , which is captured on a filter, the other component of PM10 is "condensable" particulate, which is captured in a condenser or impinger during emission testing. Pursuant to the NSR Manual, "To complete the BACT process, the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source." The only exception is if "technological or economic limitations in the application

of a measurement methodology to a particular emission unit would make an emission limit infeasible." As reflected in the draft permit, a test method is available for measurement of condensable PM, i.e., USEPA Method 202. Because emissions of condensable PM can be controlled and measured, as the Illinois EPA acknowledges, the permit for the proposed plant must contain a PM limit that includes condensable PM.

The draft permit met the requirements cited in this comment. The draft permit would have set a BACT limit related to control of condensable PM10, to specifically address the performance of the wet ESPs. These are the devices that would specifically be included in the control train for the coal-fired boilers for control of condensable PM10. The limit was expressed in terms of a surrogate, sulfuric acid mist, to address technical concerns with Method 202. The guidance cited in this comment does not preclude the use of a surrogate pollutant when setting BACT limits, as was proposed by the draft permit. This is especially so because sulfuric acid mist is generally considered to make up the bulk of condensable PM10 from a coal-fired boiler. However, as explained elsewhere, the Illinois EPA, has included a BACT limit in the issued permit that addresses total PM10, including condensable particulate. Therefore, it is not necessary to set an additional limit that only addresses condensable PM10.

178. The permit needs to establish a BACT limit for condensable PM. The draft permit contains a limit for filterable PM but there is no limit for condensable PM.

Relevant guidance from USEPA does not indicate that separate BACT limits are needed for emissions of both the filterable PM10 and condensable PM10. The issued permit retains a separate BACT limit for filterable PM10, for which there is a body of reliable emission test data from coal-fired boilers. The issued permit also includes a limit on total PM10 to address concerns and comments about the total PM10 emissions from the proposed plant.

179. The permit must set a BACT limit for condensable PM. The Illinois EPA cannot argue, as it has elsewhere, that condensable PM will be effectively controlled by the use of CFB boilers controlled with baghouses because the proposed plant will have neither.

The Illinois EPA agrees that such an argument is not relevant to the proposed plant. However, for the proposed plant, condensable PM will also be effectively controlled by the use of wet ESPs. The use of wet ESPs is required for the proposed plant because, unlike CFB boilers, control of sulfuric acid mist, a principal component of condensable PM10, is not inherent with pulverized coal boilers, so that a specific control device is needed to address it.

180. The permit must set a BACT limit for condensable PM. The Illinois EPA has argued elsewhere that it is sufficient that air quality modeling be performed for PM10 that includes both condensable and filterable PM. Whether or not air quality modeling is performed for PM10 is irrelevant to whether the proposed plant must have a PM BACT limit that includes condensable PM. This is because the BACT requirement is separate from the obligation to protect ambient air quality. The Illinois EPA has cited to the EAB decision in In re AES Puerto Rico, in support of its position to not establish a condensable PM limit. But that case is directly opposite. USEPA, Region 2, the PSD permitting agency for AES Puerto Rico, did establish limits for condensable PM in that case. The Illinois EPA must do the same for the

proposed plant.

The Illinois EPA was simply noting that the challenge posed by condensable PM10 with respect to BACT is not present for the PM10 air quality analysis. In the air quality analyses, as their purpose is to address potential effects on air quality, an upper bound estimate of the total PM10 emission rate may be used, which accommodates emissions from a source that are actually much lower. However, for the purpose of setting BACT, an adequate understanding of actual condensable PM10 emission rates is needed, as BACT must be set to both provide for the effective control of emissions and to be achievable. The Illinois EPA looks to the AES Puerto Rico case as it is guidance from the EAB on the matter of condensable PM10. In that case, before even addressing the issue of BACT for PM10, the EAB reviewed the adequacy of the air quality analysis for PM10. The case also contains an acknowledgement by USEPA of the limited amount of information available upon which to base a BACT limit that includes condensable PM and the difficulty faced by a permitting authority in setting an appropriate BACT limit for total PM10 for a coal-fired boiler. In that case, the EAB affirmed USEPA's use of "…a creative yet justifiable approach to ensuring that the permit contains effective control of condensable particulate matter."

181. The permit must set a BACT limit for condensable PM. The Illinois EPA cannot argue, as it has elsewhere, that there is limited information available upon which to base a numerical BACT limit for the condensable fraction. This position is contradicted by the fact that other power plants have condensable PM limits. According to USEPA Region 3, the Northampton plant has a permit limit of 0.0088 lbs/mmBtu and "[c]ompliance testing in February 2001 accounting for both filterable and condensable PM reports 5.75 lbs PM/hr equivalent to 0.0045 lbs/mmBtu." USEPA Region 3 is making this point because it is concerned that the proposed PM BACT limit (including condensable PM) for the proposed Longview power plant in West Virginia is inadequate. ("WVDEP has chosen a draft BACT limit for total PM/PM10, filterable and condensable PM, of 0.018/mmBtu.").

The existence of limits in permits for proposed power plants does not demonstrate that such limits are achievable, much less that they can be consistently met by the required emission control technology, as is required for a BACT limit. Certainly, the emission rate achieved in a single emission test, as reported for the Northampton CFB boiler, is not a sufficient basis to set a BACT limit for the proposed plant.

182. BACT for total PM10 is lower than 0.05 lb/mmBtu, as contained in the draft permit for the proposed plant and the BACT analysis should explicitly evaluate a much lower total PM10 rate. Several permits have been issued recently for proposed power plants with total PM10 limits of 0.018 lb/mmBtu, short-term average: Longview in West Virginia; Thoroughbred in Kentucky, and Elm Road in Wisconsin. The application for the 750-MW Trimble plant in Kentucky proposes a total PM10 limit of 0.018 lb/mmBtu. All of these plants will burn similar high sulfur, high ash coals. The Wisconsin DNR has released a draft permit for proposed Weston Unit 4 that includes a condensable PM limit. The total PM10 limit in the permit for the Springerville plant in Arizona is 0.015 lb/mmBtu. Finally, a test conducted at Deseret 's Bonanza plant in Utah measured 0.016 lb/mmBtu total PM10.

The Illinois EPA agrees that BACT for total PM10 is lower than a rate of 0.05 lb/mmBtu, as contained in the draft permit. This was the conservative (i.e., high) emission rate used for purposes of the air quality analyses. In light of recent developments, the Illinois EPA concurs that a lower conservative rate may now be used. However, the collection of information assembled in this comment does not demonstrate that a limit of 0.018 lb/mmBtu for total PM10 is achievable in the sense that the Illinois EPA believes is needed to set a BACT limit. It is also not clear that this information is reliable. In particular, while the 2002 permit issued for new Units 3 and 4 at the Springerville plant in Arizona limits particulate matter emissions to 0.015 lb/mmBtu, this limit applies to filterable particulate. Total PM10 is separately limited to 0.055 lb/mmBtu.

BACT – Startup, Shutdown, Malfunction

183. There is no record that Prairie State described the number of annual startup events. In a January 25, 2002 letter, the Illinois EPA asked Prairie State about the number of expected startup events in order to better predict Prairie State's annual emissions. This was a reasonable request because as a wholesale generator, it is not clear that the proposed power plant will operate continuously or have multiple startup/shutdown events. No response from Prairie State could be located in the materials provided by Illinois EPA. This issue must be addressed and resolved prior to issuing a permit.

Prairie State adequately responded to the Illinois EPA's January request for information in its October 2002 submittal, with information confirming the plant would be a base load facility. As a base-load power plant, the proposed plant would generally have only a small number of startups per year and would operate for long periods of time between startups and shutdowns. The fact that the proposed plant would be classified as a wholesale generator of power under FERC means that the plant would not directly sell power on a retail level. It does not mean that the plant would not serve as a base-load source of power for the entities to which power is sold, which do distribute power at the retail level.

184. The draft permit provides that, "the emissions from each boiler shall not exceed the following limits except during start up, shut down, and malfunction as addressed by Condition 2.1.2(e)." The EAB's decision on the RockGen Energy Center appeal (99-1) provides guidance on provisions relating to periods of start up or shut down of a facility. The EAB determined that the Wisconsin DNR could make an on-the-record determination as to whether compliance with existing permit limitations is infeasible and, if so, what permit provisions are appropriate to minimize excess conditions. If the permitting authority determines that compliance with an applicable limit cannot be achieved during start up and shut down despite best efforts, it should specify and carefully circumscribe in the permit the circumstances under which the facility would be permitted to exceed otherwise applicable emission limits and establish that such conditions are nonetheless in compliance with applicable requirements, assuming that national ambient air quality standards and increment provisions are not threatened. In such case, the Illinois EPA may include a secondary PSD limit, provided it is made part of the permit and justified as BACT. However, it is not clear that the record for the proposed plant contains an adequate analysis for the use of a justified

secondary BACT for startup, shutdown, and malfunction periods. Such an analysis is required.

The issued permit includes changes from the draft permit that respond to this comment, so that the proposed BACT requirements generally extend to periods of startup, shutdown and malfunction for the two coal-fired boilers or alternative limits apply to address such events. These changes reflect a further project-specific evaluation of the circumstances of the proposed boilers by the Illinois EPA. This includes both the physical circumstances, that is, the capabilities of the boilers and control devices that are being used, the size of the boilers and the possible duration of startup events. It also includes reconsideration of the compliance methodology that may be used to determine compliance with BACT limits. These changes also reflect the desire of Prairie State to eliminate a potential issue that could lead to an appeal of the permit by the public. These changes do not reflect a determination that the emission rates of the boilers will not be affected by startup or shutdown. The performance of the boilers during low operating temperatures as occur during startup and shutdown is of particular concern as CO emissions from the boiler and control of NOx emissions in the SCR would clearly be affected.

For PSD pollutants for which continuous emissions monitoring is required, the issued permit includes BACT limits that apply at all times, including periods of startup, shutdown and malfunction. For NOx and SO_2, for the BACT limits set in terms of lb/mmBtu on a 30-day average, the limits in the issued permit to cover all operation. For a 30-day period that includes a startup or shutdown (NOx only), compliance with the BACT limit may be determined on a mass-basis, by dividing the total emissions of NOx during such period to the total heat input during the period, rather than on a rate-based average using the methodology of the NSPS, as generally applicable. This reflects the Illinois EPA's experience with industrial boilers, which found that the rate-based compliance methodology of the NSPS is problematic when applied to stringent BACT limits. This is because a partial day in which a boiler starts up and experiences a high startup emission rate is not weighted for the actual extent of operation during the day. Instead, it is averaged with other days and given equal weight as days when the boiler operated at normal load. Without this provision for an alternative compliance methodology, the BACT limits for SO_2 and NOx could not be extended with the necessary confidence that compliance is reasonably achievable with the BACT limits. For CO, for which BACT is set on a daily basis, an alternative BACT limit is set for startup and shutdown, which limits emissions to the permitted emissions of the boiler, in lb/hour, 24-hour average for such a period. This reflects the Illinois EPA's judgment that with a 24-hour compliance time period, as applicable for CO, it is not feasible to simply extend the BACT limit to cover startup, shutdown and malfunction as is being done for SO_2 and NOx.

For other PSD pollutants for which continuous emissions monitoring is not performed (or not performed for the purpose of directly determining compliance), secondary BACT limits to address periods of startup, shutdown and malfunction are set using the permitted emission rates of the boilers in lb/hour, 3-hour average. The application of these emission rates to the coal-fired boilers for this purpose depends upon use of engineering evaluation as the compliance methodology for such periods, as was suggested by a public comment. In particular, it is not intended that emissions testing be attempted for the purpose of measuring

emissions during startup or shutdown. It is also not expected that the particulate continuous monitoring systems will be able to be calibrated to allow data collected during such periods to be reliably correlated with actual rates of emissions.

In addition, the issued permit retains the provisions of the draft permit that required that the source follow good air pollution control practices for the coal-fired boilers to minimize emissions by operating in accordance with detailed written operating procedures, maintaining each boiler and associated air pollution control equipment in accordance with good air pollution control practices to assure proper functioning of equipment and minimize malfunctions, handle the fuel for the boilers in accordance with a written Fuel Management Plan, and review such procedures, at least annually, and revise them if needed. Specifically, reasonable practices must be used to minimize emissions during startup and shutdown of the boilers. Furthermore, these practices must include the use of natural gas during startup to heat the boilers prior to initiating the firing of coal, operation of the boilers and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s), and inspection, maintenance and repair of the boilers and associated air pollution control equipment in accordance with written maintenance procedures.

185. The waiver of BACT limits during startup, shutdown, and malfunction events is improper. The draft permit waives the BACT limits for both the coal boilers and the auxiliary gas boiler during startup, shutdown and malfunction events. There is no demonstrated need for the wholesale elimination of BACT limits during startup, shutdown and malfunction events. A PSD permit must include stringent requirements to ensure compliance with the Clean Air Act during startup, shutdown and malfunction and must be consistent with US EPA's guidance. Memo from Kathleen Bennett, *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions*, Sept. 28, 1982 (Bennett Memo); Memo from Steven Herman, *State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown* (Sept. 20, 1999)

The Bennett Memo prohibits automatic *exemptions* for excess emissions during startup, shutdown and malfunction. USEPA is particularly intolerant of excess emissions during start-up and shutdown. "Start-up and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation or the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods." Instead of requiring Prairie State to carefully plan to minimize violations of short-term emission limits Illinois EPA simply exempts the source from complying with short-term emission limits during startup, shutdown and malfunction events altogether. This is contrary to the requirements of BACT.

This comment is no longer relevant given the provisions of the issued permit for the coal-fired boilers. In addition, it misapplies historic guidance for development of State Implementation Plans to the PSD program. It is also improper to characterize the approach taken in the draft permit as an "automatic waiver" of BACT. Rather the draft permit followed the approach to startup, shutdown and malfunction events generally taken by USEPA for its MACT and

NSPS regulations, including the NSPS standards that apply to the coal-fired boilers. This is addressing startup, shutdown and malfunction events with a broad requirement to use good air pollution control practices. This approach is consistent with provisions in the definition of BACT that allow work practices to be set in circumstances where technological or economic limitations on measurement methodology make imposition of an emission standard infeasible. This is commonly the case with emissions during startup and shutdown, as emission testing during such periods is problematic and emissions monitoring may not be as reliable. A requirement for good air pollution control practices is also a rigorous approach to the operation of emission units during such periods. It can be considered a more rigorous approach than the setting of emission limits whose basis is uncertain and must be set to accommodate the variable nature of startup, shutdown and malfunction events, and cannot be adapted and enhanced with actual experience. It also should not necessarily be assumed that such an approach authorizes what would otherwise be violations of applicable limits. Rather it simply reflects a different approach to addressing startup, shutdown and malfunction events. This approach is still appropriate for the natural gas-fired auxiliary boiler, whose operation is limited to an auxiliary role and is not equipped with any continuous emissions monitoring systems.

186. According to the NSR Manual, BACT limits must be enforceable as a practical matter. BACT limits, as gutted by the startup, shutdown and malfunction provision, do not meet this requirement. Prairie State's limits are not required to be met because all short-term limits are suspended whenever Prairie State declares it is having a startup, shutdown and malfunction event. There are multiple consequences of having no short-term permit limits, such as the absence of authority to bring an enforcement case seeking relief to address the underlying reason for excess emissions during a startup, shutdown and malfunction event, as appropriate.

This comment poses a key point concerning the approach to BACT during periods of startup, shutdown and malfunction. This is whether numerical emission limits are enforceable as a practical matter during periods of startup, shutdown, and malfunction, if emission tests cannot be conducted during such periods to determine compliance. As already noted, a requirement for good air pollution control practices also provides practical enforceability and provides an adequate basis to pursue enforcement for improper operation or maintenance. It is certainly adequate to address gross exceedances, e.g., circumstances where control devices fail to function, in which exceedances of emission limits could be readily or conclusively shown with credible evidence. However a requirement for good air pollution control practices is also effective for other lesser exceedance events, in which a pattern of improper or inadequate operation or maintenance can be perceived but exceedances of an emission limit are not readily demonstrated with credible evidence. Accordingly, the addition of supplemental BACT limits to the permit has not been accompanied by removal of requirements that good air pollution control practices be followed.

187. The wholesale elimination of short-term emission limits during Prairie State's startup, shutdown and malfunction events also violates BACT because Prairie State has not demonstrated that it can protect short-term ambient air quality standards without such limits. *See e.g.* Memo from Gerald Emison, OAQPS to David Kee, Region 5 (Oct. 24, 1986). In

this memo Mr. Emison responds to a Region 5 statement that PSD permits must contain short-term emission limits to ensure protection of ambient air quality standards: "I concur with your position and emphasize to you that this position reflects our national policy."

The issued permit for the proposed plant contains necessary provisions to protect ambient air quality standards. It is not necessary that these provisions be set as numerical BACT limits. In this regard, the issued permit includes various changes to the provisions setting limits on the permitted emissions as necessary to protect short-term air quality.

188. There are reasonable "work practice" options to reasonably constrain startup, shutdown and malfunction events without throwing out all short-term limits. One important procedure to minimize startup emissions is to use natural gas for the first few hours until the boiler temperature exceeds a certain temperature and at that point begin firing coal. Perhaps the permit should include such a requirement, *i.e.*, no firing coal until the boiler temperature exceeds 900 ºF. Moreover, Illinois EPA must assess whether the estimated emission levels during startup, shutdown and malfunction events are within the BACT limits – if so, no waiver is necessary.

The draft permit included and the issued permit continues to include work practices such as those suggested by this comment, to constrain emissions during startup, shutdown and malfunction events.

189. Based on the startup, shutdown malfunction provision in the draft permit, it would be conceivable that the proposed plant could operate completely uncontrolled for extended periods during such events. An analysis was not found in Prairie State's application that showed that uncontrolled emissions for a significant period of time would not violate short-term air quality standards.

Uncontrolled operation for an extended period of time was not allowed by the draft permit, as suggested by this comment. Such operation would not be consistent with good air pollution control practices and is therefore prohibited.

190. Periods of startup and shutdown were improperly eliminated from BACT limits. The draft permit would exclude startups and shutdowns from compliance with the BACT limits. The NSR Manual notes that BACT emission limits "must be met on a continual basis at all levels of operation." There is no exemption for periods of startup and shutdown.

The guidance cited in this comment is one reason that the draft and issued permits explicitly address BACT during startup and shutdown. In the absence of such explicit statements of the alternative requirements that apply during startup and shutdown events, the "generally applicable" BACT limits would apply at all times. However, this guidance does not prohibit the establishment of such alternative requirements.

191. The USEPA has consistently defined startup and shutdown to be part of the normal operation of a source. The USEPA has also consistently concluded that these emissions should be accounted for in the design and implementation or the operating procedure for the

process and control equipment. USEPA has concluded that "[w]ithout clear definition and limitations, these automatic exemption provisions [for startups and shutdowns] could effectively shield excess emissions arising from poor operation and maintenance or design, thus precluding attainment." (Bennett Memo, 9/28/82.) Accordingly, it is reasonable to expect that careful planning will eliminate violations on emission limitations during such periods. *Id.* The exemption for startups and shutdowns in the draft permit should not be carried over into any issued permit.

As noted in the comment, the concern addressed in this guidance from USEPA is <u>attainment</u> of air quality standards. The guidance is not directly relevant to an area where air quality standards are met, much less to the requirement for BACT under the PSD rules. The comment also is not relevant, as the draft permit did not provide an "automatic exemption" for periods of startup and shutdown. Rather, the draft permit required, and the permit still requires, in addition to other requirements, that the plant use good air pollution control practices for periods of startup and shutdown. This does not shield the plant for excess emissions arising from poor operation, maintenance or design, or excuse the plant from careful planning to eliminate or minimize emissions during periods of startup and shutdown.

192. There are better, more protective ways to address Prairie State's as-yet-undemonstrated need for flexibility during startup, shutdown and malfunction events than eliminating all short-term BACT limits. A PSD permit must ensure continuous, enforceable limits in place at all times. The approach in the draft permit violates BACT and is unnecessary to provide some limited flexibility.

While it may be true that there are better ways to address Prairie State's potential need for flexibility, this comment does not provide any suggestions as to what such ways might be. In contrast, when developing emission standards, USEPA has routinely established work practice requirements for periods of startup, shutdown and malfunction, as an alternative to compliance with numerical emission limits. This is the approach that was broadly followed in the draft permit.

193. The draft permit would require Prairie State to develop a plan to "address start up, normal operation, and shutdown and malfunction events" without subjecting such plan to public scrutiny as mandated by 40 CFR.52.21 and 52.124. In the absence of a formal permit modification proceeding, such a plan would not be federally enforceable and is therefore unlawful.

The comment misunderstands this provision of the draft permit. The provision in question requires Prairie State to <u>develop</u> and <u>operate</u> pursuant a particular plan that it prepares, consistent with USEPA regulations governing such plans. This requirement is clearly stated and is fully enforceable. However, the provision does not contemplate that the details of the plan would be directly enforceable in the same manner that a numerical BACT limit is enforceable.

MACT – General

194. Prairie State's proposal does not reflect MACT for the control of mercury and other HAPS**.** The floor for a MACT standard under Section 112(g), i.e. the statutory minimum stringency – must reflect the "emission level achieved" by the relevant best performing sources. See Cement Kiln Recycling Coalition v. USEPA, 244 F.3d 855, 865 (D.C. Cir. 2001) (hereinafter "CKRC") (this case involves CAA §112(d), but has similar statutory language). For a new source, such as Prairie State, this must reflect the emission level achieved by the single best performing similar source. The D.C. Circuit has made plain that in setting standards under Section 112(d) of the Clean Air Act, USEPA may not use the performance of a chosen control technology as an estimate of the emission levels achieved by the best sources, where other factors also influence such performance: The same legal reasoning applies in setting a case-by-case MACT standard under Section 112(g)(2) of the Clean Air Act. For example, USEPA has stated "[b]oilers and process heaters can emit a wide variety of compounds depending on the fuel burned." Similarly, USEPA has offered that "In addition, control devices of the same type can and do vary widely in performance, and some sources may use more than one end-of-stack control technologies or a combination of different control technologies." Finally, power plants are operated differently; different companies require different levels of training, operator care and equipment maintenance. All of these factors – in addition to the variations in fuel used and the different types of control device installed – affect HAP emission levels. In short, it matters not how sources achieve their superior emission levels, they may do so by burning cleaner fuel, by being better designed or newer, by being better maintained or operated, by using better end-of-stack control technologies, by using more than one control technology, or by using different combustion technologies, such as CFB and IGCC. The Illinois EPA has the simple but mandatory task to identify the best performing sources – regardless of how they are achieving their superior emission levels – and set Prairie State's emission levels based on the single best performing source. Anything less would be contrary to the Clean Air Act.

The principles reviewed in this comment are not relevant to the case-by-case determination for MACT for the proposed plant under Section 112(g) of the Clean Air Act. Among other things, this is because this action is not a regulatory action, i.e., the determination being made is a case-by-case determination for a single plant. In addition, variation in the HAP content of fuel is a factor that USEPA has considered and addressed in its adopted rulemaking for industrial, commercial and institutional boilers. During its rulemaking for utility boilers, USEPA specifically solicited comments on approaches to source emission variability. It also described an alternative approach to addressing variability in the composition of coal put forth by the USDOE, which resulted in a higher MACT floor, 2.6 lb mercury/trillion Btu, than the MACT floor identified by USEPA.

The permit reflects an appropriate case-by-case determination of MACT for the proposed plant in accordance with the requirements of Section 112(g) of the Clean Air Act and USEPA's regulations at 40 CFR Part 63. In general, MACT determinations under Section 112(g) must represent the level of emission control that is achieved by the best-controlled similar source. In particular, the MACT determination for the proposed coal-fired boilers is based upon the performance of other pulverized coal utility boilers that are firing bituminous

coal.

MACT - Mercury

195. On January 30, 2004, the USEPA proposed MACT standards for emissions of mercury from electric utility boilers, (69 FR 4664 *et seq*.). The draft permit would set a case-by-case emission limit for mercury of 20 lb/million MW-hr, which is higher than the limit proposed by USEPA for new boilers firing bituminous coal, as would occur at the proposed source. The Illinois EPA should further examine the USEPA's rulemaking docket to determine whether a case-by-case limit for mercury can be set for this plant that is identical to the applicable limit proposed by USEPA. The Illinois EPA's record for this project must clearly explain and document the Illinois EPA's determination (including consideration of USEPA's proposed rule) and the basis for the selected case-by-case mercury limit.

As a general matter, federal regulations for control of mercury emissions from utility boilers, including the regulations recently adopted by USEPA on March 15, 2005, would apply to the proposed plant. The case-by-case determination of MACT in the permit, would not act to shield or exclude the proposed plant from the applicable requirements of the regulations that USEPA recently adopted for control of mercury emissions from utility boilers or from any future regulations that USEPA may adopt for control of mercury emissions, when these regulations become effective. The case-by-case determination of MACT is included in the issued permit because it is not clear that the recent rules adopted by USEPA are adequate, that is, that the USEPA has met its obligation under the Clean Air Act with respect to control of mercury emissions. This is because it is almost certain that the USEPA's recent rulemaking will be challenged, as USEPA acted under Section 111, rather than Section 112 of the Clean Air Act. The case-by-case determination covers the possibility that the Courts agree with such a challenge and find that USEPA's recent regulations are not adequate to meet its obligations under Section 112 of the Clean Air Act.

As a technical matter, the Illinois EPA has further reviewed USEPA's rulemaking docket, as specifically requested by this comment. The Illinois EPA also has reviewed other comments concerning control of mercury emissions that were submitted and information concerning control of mercury emissions that has generally become available since the draft permit was prepared. As result of this review, the case-by-case MACT determination in the issued permit differs in a number of respects from that in the draft permit. The key change is that the permit does not attempt to set a numerical limit for MACT, expressed in lb/mmBtu heat input or lb mercury/MW-hour of output, as USEPA did in its proposed, or adopted, regulations. Instead, the issued permit provides two options for control of mercury emissions, either (1) achievement of at least 95 percent control through co-benefit with the control train for other pollutants, or (2) effective control of mercury emissions using a sorbent injection system specifically installed for control of mercury emissions. Because a numerical emission limit will not be available against which to evaluate the performance of the sorbent injection system, the issued permit also includes procedures that set forth how the required level of sorbent injection for optimized control of mercury is to be determined.

196. Did Prairie State use the average mercury content in the proposed coal, or as typically done,

consider the maximum potential to emit based on the maximum mercury content?

The application reflects the maximum mercury content of the coal supply, as is appropriate for both establishing the permitted mercury emissions of the proposed plant and evaluating the level of control that is being required for mercury emissions.

197. According to the ICR data collected by USEPA, the best performing coal boiler in terms of mercury removal efficiency is the Kline Township Cogeneration facility. The ICR data for this plant showed 99.95 percent control of mercury emissions and an emission rate of 0.0818 lb/trillion Btu.

The Kline Township Cogeneration facility does not set the MACT floor for the coal-fired boilers because it is not a similar source to the proposed boilers. It burns coal waste and is a circulating fluidized bed boiler.

198. Prairie State's proposal of a 79 to 80 percent mercury reduction (at a rate of 2.05 lbs/trillion Btu) is significantly higher than that being achieved by other power plants. According to USEPA's ICR data, the mercury emissions of the Logan and Clover plants in Pennsylvania were 0.281 lb/trillion Btu and 0.3529 lb/trillion Btu, which reflected achievement of 96.71 percent removal at both plants. The recently permitted Longview plant in West Virginia has a mercury limit of 1.46 lb/trillion Btu. Even plants burning sub-bituminous coal are proposing greater mercury reductions than Prairie State. For example, Mid-American Energy's new Unit 4 at Council Bluffs, Iowa, was recently-permitted with activated carbon injection to achieve a mercury emission limit of 1.7 lb/trillion Btu, based on 83% removal. Illinois EPA is on record stating that mercury reduction from bituminous coal is cheaper and easier than from sub-bituminous coal.

Independent of the mercury limit proposed by Prairie State for the proposed coal-fired boilers, the numerical limit for mercury emissions in the draft permit reflected the numerical limit proposed by USEPA for existing pulverized coal-fired boilers. It also reflected the limits for new coal-fired boilers burning sub-bituminous coal and new IGCC power plants. At the time that the draft permit was issued, the Illinois EPA did not find that the limit proposed by USEPA for new pulverized coal boilers burning bituminous coal was based upon a sufficient body of data to allow the Illinois EPA to conclude that the proposed limit was achievable in practice.

However, the Illinois EPA has not carried over the numerical emission limit in the draft permit to the issued permit because information, including the data accompanying this comment, indicates that more effective control of mercury emissions, expressed in lb/MW-hr or lb/trillion Btu, can be achieved and is being required at other new plants for mercury emissions. This information also strongly suggests that the proposed coal-fired boilers will be able to comply with the numerical limit that USEPA proposed as MACT for boilers firing bituminous coal, i.e., 6.0 lb/million MW-hr or about 0.6 lb/trillion Btu. In part, this conclusion is based on actual performance data for control of mercury emissions by co-benefit, such as the data provided in this comment for the Logan and Clover plants in Pennsylvania, which shows 95 percent control with co-benefit. (Because ICR data reflects a

small number of individual emissions tests, it is not appropriate to rely on this data for an exact level of control efficiency achieved by co-benefit.) In part, this conclusion is also based on continuing progress in developing add-on mercury control technology in the years before the plant begins operation. If such efforts are successful, the research to date suggests that sorbent injection is a technique that would be available and could be applied to the proposed plant for control of mercury emissions from the coal fired boilers to make up for any deficiency in the amount of control provided by co-benefit.

Current information still does not demonstrate that 95 percent control of mercury is achievable now or will be achievable when the proposed coal-fired boilers begin operation. For new boilers, USEPA's proposed rules relied upon continued progress in the development of mercury control technology and a standard that would have a compliance date out in the future. Accordingly, if 95 percent control of mercury is not achieved on the proposed boilers with co-benefit, sorbent injection is an appropriate add-on control technology that should be required as it is generally applicable to coal-fired utility boilers and has been demonstrated to be effective in controlling mercury emissions. Thus, the issued permit provides two compliance options for control of mercury emissions from the coal-fired boilers: (1) co-benefit to achieve at least 95 percent control, and (2) effective use of add-on sorbent injection systems.

The Illinois EPA's evaluation of this matter, as described above, is not altered by material compiled by USEPA in preparation for its adoption, on March 15, 2005, of final rules for control of mercury emissions from utility boilers. In particular, co-benefit or use of add-on sorbent injection systems continue to be identified as the appropriate technology for effective control of mercury emissions. While USEPA has adopted a higher emission limit for mercury than proposed for boilers fired with bituminous coal, 15 lb/million MW-hour rather than 6 lb/million MW-hour, this final limit or a limit expressed in these terms, i.e., lb/MW-hour, is not appropriate as MACT for the proposed plant based on the Illinois EPA's case-by-case evaluation. This evaluation indicates that MACT for mercury emissions is best addressed by requirements that directly address application of emission control measures rather than by establishment of a numerical emission limit.

199. The starting point for setting Prairie State's mercury MACT limit must be the best performing source, i.e. the Kline Township facility with its emission of 0.0816 lb/trillion Btu. Even if it was appropriate to subcategorize a determination of the best controlled similar source based on coal type, which it is not, the best controlled bituminous coal-fired power plant is Mecklenburg Cogeneration Unit 1 which is achieving a rate of 0.1062 lb/trillion Btu, a 98.5% mercury removal.

The Mecklenberg Cogeneration facility contributes to the data for setting the MACT floor. It cannot be used by itself to set a MACT floor because it is not accompanied by sufficient data addressing the long-term performance of the facility for mercury emissions or the effect of the composition of the coal used at the facility on the emission rates that are achieved.

200. While not endorsing USEPA's proposed mercury MACT rule, USEPA has defined a category of similar sources in setting its MACT limits as bituminous coal-fired power plants. USEPA did not further subcategorize such boilers based on whether they were

pulverized coal boilers or CFB boilers. This definition of similar source is sufficiently broad to also include IGCC power plants.

This is not entirely correct. As previously noted, USEPA placed IGCC power plants and boiler-based power plants in different categories. It also is significant that USEPA placed "coal-fired" boilers in different categories depending upon whether bituminous coal, sub-bituminous coal, lignite, or coal refuse was being burned.

201. Prairie State's mercury limit does not consider a beyond-the-floor limit.

The case-by-case mercury limit for the proposed plant is generally based on USEPA's proposed MACT rulemaking, and is consistent with the analysis that USEPA has conducted with respect to a beyond-the-floor limit. In this regard, USEPA has indicated that it has not considered beyond the floor limits for mercury. However, it is arguable that such consideration has occurred, especially for new sources, as the USEPA's rulemaking relies upon the continued development of control technology for mercury.

202. Prairie State did not fully and fairly evaluate control technologies that could achieve the maximum degree of reduction in mercury emissions beyond the MACT floor. Thus, the MACT analysis failed to address the principle of MACT determinations that essentially calls for an evaluation of all available control technologies, similar to the process required in determining BACT (40 CFR 63.43(d)(2)). This evaluation must also include technologies in use outside the United States.

The Illinois EPA's evaluation included consideration of available control technologies for mercury emissions. As a general matter, two basic approaches are being pursued. One is co-benefit, i.e., design and operation of the existing air pollution control train to also effectively control mercury emissions. The other approach is direct control of mercury emissions, typically by injecting a sorbent, usually activated carbon, into the flue gas.

203. A comparison of the definition of MACT to the definition of BACT used in the PSD program shows that the two definitions are almost identical, except that the floor for determining BACT is the applicable NSPS whereas the floor for determining MACT is the emissions control that is achieved in practice by the best controlled similar source. Consequently, to determine MACT for the proposed plant, the top-down approach of the PSD program should have been used for determining MACT for the HAPs emitted by the unit after determining the MACT floor. Such an approach would ensure that the potential control technologies that would achieve the maximum emissions reduction are fairly evaluated. The first steps in the top-down BACT process that should apply to a case-by-case MACT determination is the identification of all available control options that have a practical potential for use on an emissions unit.

While the definitions of MACT and BACT are similar, they are not identical. As noted by this comment, MACT is generally based on the emission rate that is achieved in practice by the best performing units and does not have to include a "technology-forcing" analysis of what may be achievable on a case-by-case basis for a proposed project. In contrast, it is commonly

accepted that a BACT determination can be technology forcing.

204. In determining the control technology underlying MACT, a permitting authority must consider alternative processes and techniques that reduce or eliminate HAP emissions in addition to technologies that collect or treat HAPs. See definition of "control technology" at 40 CFR 63.41. Such alternative processes or techniques would include the evaluation of an IGCC plant as an alternative process for producing electricity. Studies have shown that it is cost-effective with IGCC to control mercury emissions by 90% or more with available carbon bed technology.

IGCC does not need to be considered as an available control technology in the MACT evaluation for the proposed plant. This is because USEPA did not consider it as a control alternative for coal-fired boilers in its proposed MACT rulemaking, which places IGCC in a different source category than boilers. In addition, similar levels of control for mercury appear to be achievable for coal-fired boilers with activated carbon injection technology.

205. With IGCC technology, high levels of mercury reduction can be achieved cost-effectively. The U.S. Department of Energy (USDOE) states that "mercury removal in an IGCC power plant can be expected to be very high in removal effectiveness, low in cost, and reliable in design." USEPA in its January 30, 2004 proposed MACT rulemaking found that carbon bed technology is an available mercury control technology for IGCC power plants and that 90-95% mercury control can be achieved. 69 FR 4676-7. Prairie State should have thoroughly evaluated an IGCC plant with carbon bed technology as an alternative process for control mercury emissions.

The comment fails to fully describe the action that USEPA took with respect to IGCC plants in its proposed MACT rulemaking proposal, as it treated them as a different category of source than pulverized coal plants. It is also significant that USEPA proposed a mercury limit of 20 lb/million MW-hr for new coal plants using IGCC technology. This is identical to the numerical emission limit for mercury that was contained in the draft permit for the proposed plant.

206. Pursuant to the definition of "available information" in 40 CFR 63.41, a permitting authority is required to consider various sources of information, such as background information on proposed regulations and information provided by the applicant or others, in evaluating the maximum degree of reduction in mercury emissions that can be achieved. USEPA's utility MACT rulemaking website includes a wealth of information on mercury reductions currently being achieved by the various power plants across the country and on full scale testing of mercury control technologies. Further, in October 2003, USEPA published "*Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers*," EPA-600/R-03- 110, October 2003. This document includes control efficiency and cost information for activated carbon injection as well as other potentially applicable mercury control techniques. In spite of the volume of available information on mercury control, Prairie State gave brief mention to possible controls. Thus, the draft permit did not address the second principle of MACT determinations to fully and fairly evaluate those control technologies that could be applied to achieve the maximum

degree of reduction in emissions of mercury. Prairie State's MACT determination must be redone to consider additional mercury control technologies.

The MACT determination for mercury in the draft permit reflected an appropriate evaluation of available and developing control technology for mercury. Most significantly, it relied on the evaluation of control technology performed by USEPA for its proposed rulemaking. It also relied on other information on control technology for mercury. The critical issue for this evaluation is that much of the information reflects developing technology that is not yet commercially available.

In this regard, the cited USEPA report on research and development of control technology for utility boilers speaks for itself. As stated in the summary of this report, "It is expected that R & D are likely to focus on improved understanding of both mercury speciation across SCRs and the beneficial effects of the combination of SCR with wet FGD, and on developing sorbents that can improve performance and cost of sorbent-based mercury control technologies." Other possible control technologies are described as areas for which further development is needed.

207. Use of sorbent injection for mercury control should have been thoroughly evaluated. Prairie State failed to consider the use of sorbent injection, such as activated carbon injection, for removal of mercury. Pilot-scale and full-scale testing has been performed at many coal power plants using carbon injection for mercury control, and the results have consistently shown high levels of mercury control. This is especially true for plants equipped with baghouses. The results of the full scale studies performed by ADA-ES are all available on the USEPA's utility MACT website.

Use of sorbent-injection technology was appropriately considered by the Illinois EPA. It is the basis of one of the compliance options in the case-by-case MACT determination.

208. The recent MACT determination for the Mid-American Energy, Council Bluffs, Unit 4, requires use of a sorbent injection system for control of mercury emissions. This new unit will burn subbituminous coal from the Powder River Basin of Wyoming and the permit requires an 83% reduction in mercury emissions. This demonstrates that sorbent injection technology is available, that high levels of mercury reductions can be achieved with sorbent injection at a plant, and that the cost of achieving such a level of control was considered reasonable by the Iowa Department of Natural resources. The website of the company that performed all of the full-scale studies of sorbent injection at coal-fired power plants, ADA-ES, indicates that sorbent injection is "proven technology" that "works for all coal plants and configurations," is "cost effective," and "available now." See www.adaes.com under "Mercury Control and Measurement."

This development is another piece of data that confirms that sorbent injection is a control technology that can be applied to coal-fired boilers. However, as boilers burning low-sulfur western sub-bituminous coals are a different category of source than boilers burning bituminous coals, it does not demonstrate that injection is needed for effective control of mercury emissions.

209. Activated carbon is clearly an available technology for removing mercury from gas streams. The technology has been used for at least seven years at municipal waste combustors, where it achieves 95 % to 98% mercury removal efficiency. The technology has more recently been tested on coal-fired power plants across the U.S. Various control technology vendors state that it is available now. Activated carbon injection is proposed on Comanche, Unit 3, in Colorado.

The Illinois EPA agrees that activated carbon injection is an available control technology for mercury emissions. However, the performance of activated carbon on mercury emissions of coal-fired boilers, with their lower loadings of mercury, may not be comparable to the levels of control achieved at municipal waste incinerators with their higher mercury loadings.

210. The costs of activated carbon technology are reasonable. The costs for activated carbon injection for the proposed plant would be similar to the costs that MidAmerican Energy will incur for the sorbent injection system at its new Council Bluff, Unit 4. Studies have indicated that 90% mercury reductions can be achieved with activated carbon injection at a plant equipped with a fabric filter and would cost roughly $50 to $1,266/MW-hr. Information on the costs of activated carbon relative to the costs of other pollution control equipment for the proposed Roundup Power plant in Montana show that the costs of a sorbent injection system are a fractions of the cost of other control equipment, i.e., approximately 1% of the total capital costs of all control equipment and less than 10% of the annualized cost of controls. At the same time, there will be tremendous benefits to the environment associated with controlling 90% to 95% of the mercury emissions.

The Illinois EPA agrees that costs of activated carbon injection are reasonable for control of mercury emissions <u>if</u> mercury emissions are not otherwise being effectively controlled by co-benefit from the control devices present on a boiler. Council Bluffs, Unit 4, does not provide relevant information to answer this question for the boilers at the proposed plant. This unit is designed to burn western sub-bituminous coal from the Powder River basin, a coal supply for which control of mercury is generally considered more difficult than with bituminous coal. Even with activated carbon injection, the mercury limit set for Unit 4 is 1.7 lb/million mmBtu, based on achievement of 83 percent overall control after carbon injection. This emission limit is not significantly lower than the mercury limit proposed in the draft permit for the proposed plant. At the same time, Unit 4 will not be equipped with high-efficiency scrubbers like those required on the proposed boilers. The SO_2 scrubber on Unit 4 need only achieve about 85 percent control (0.1 lb SO_2/mmBtu, from an uncontrolled rate of 0.625 lb/mmBtu). Accordingly, the potential for mercury co-benefit from the scrubber on Council Bluffs, Unit 4, is lower than that of the scrubbers at the proposed plant.

211. Activated carbon also will help control other HAPs as well, including volatile organic compounds, arsenic and dioxin. Indeed, activated carbon is considered a control technology for dioxin emissions at municipal and medical waste combustors. Such co-benefits in reducing other HAP emissions with activated carbon use must be considered in fully evaluating activated carbon as part of the MACT above-the-floor analysis.

The Illinois EPA agrees that activated carbon injection may provide some additional control for emissions of HAPs other than mercury if emissions of such HAPs are not otherwise being addressed by the control devices present on a boiler.

212. The Illinois EPA must closely examine pre-combustion fuel treatment as a means of achieving significant emissions reductions. In particular, the Illinois EPA must examine the use of K-Fuel as an option for inherently lower mercury emissions as well as lower criteria pollutant emissions. K-fuel is coal that is treated by a pre-combustion process to improve quality, to remove water and increase heat content, which also removes some of the mercury, sulfur and nitrogen contained in the coal. The process transforms low Btu, high moisture content coal into a high Btu, low moisture content fuel.

USEPA did not identify pre-combustion fuel treatment as a technique that should be counted on for control of mercury emissions. In addition, while pre-treatment has promise, it is as another step that could provide co-benefit for reduced mercury emissions. It does not provide the overall reduction in mercury emissions provided by other approaches.

For example, as noted in the comment, K-Fuel is not a treatment technology targeted for bituminous coal. It is a technology that is still being developed that is targeted for low Btu, high moisture Western sub-bituminous coal. In addition to its potential benefits for drying such coal and increasing its heat content, K-Fuel is also reported to have the potential to lower mercury levels. This would be a fortunate side benefit from the process, as the mercury emissions of sub-bituminous coal are still not as readily collected with traditional add-on control devices as would be if bituminous coal were used. This appears to be due to the predominance of elemental mercury in the exhaust from burning sub-bituminous coal, which may be a consequence of the lower levels of sulfur and chlorine in the coal with which mercury may combine. However, it would also be important to verify that K-Fuel achieves a real reduction in the mercury content of the coal, not just an apparent reduction from the higher heat content of the coal.

213. There are also several other mercury control technologies that could be employed at Prairie State as detailed in EPA's October 2003 "Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers." These technologies include electro catalytic oxidation (ECO) technology and advanced dry flue gas desulfurization. The Illinois EPA must consider these available technologies in its MACT analysis.

Innovative control technologies, including those listed in the cited document, have been considered. They do not provide an appropriate basis to set BACT for the proposed plant.

214. The MACT limit must consider non-air impacts. The MACT limit must be based on consideration of "non-air quality health and environmental impacts" in determining the maximum degree of reductions in emissions that are achievable and establishing limits for the proposed plant. 40 CFR 63.41. USEPA has recognized that such impacts exist. See e.g., 64 FR 52,828, 53,014 (Sept. 30, 1999); 64 FR 31,898, 31,908-31,909 (June 14, 1999); 63 FR 14,182, 14,193 (Mar. 28, 1998); 61 FR 17,358, 17,478) (Apr. 19, 1996). Every lake and

stream in Illinois is under a fish-consumption advisory because of mercury contamination. This demonstrates a clear need to reduce mercury emissions in Illinois and other states. It also demonstrates that the proposed plant must be held to lowest mercury emission rate possible.

USEPA's historic determination that mercury emissions have non-air quality health impacts is the reason that USEPA proposed MACT standards for boilers and the reason that the proposed plant is subject to a case-by-case determination of MACT.

MACT – Pollutants Other Than Mercury

215. The draft permit does not reflect MACT for the control of HAPS other than mercury. The proposed limit for hydrogen chloride does not reflect MACT.

The permit reflects MACT for emissions of HAPs other than mercury, including emissions of hydrogen chloride, as appropriate control technologies are required and limits are set that require effective operation of these technologies. In addition, for emissions of hydrogen chloride from the coal-fired boilers, which are also controlled by the SO_2 scrubbers, specific limits are set in terms of hydrogen chloride, i.e., at least 98 percent control of hydrogen chloride or no more than 0.0032 lb hydrogen chloride/mmBtu.

216. The permit does not address the MACT floor or consideration of all available control technologies for the maximum control of HAPs other than mercury emitted by the proposed plant.

The MACT floor recognized for coal-fired boilers is (1) good combustion practices, (2) effective control of acid gas emissions, as achieved through scrubbing, and (3) effective add-on control of particulate emissions. These control components are present for the proposed boilers, which would be equipped with electrostatic precipitator, flue gas desulfurization and wet electrostatic precipitator. The MACT floor for units other than combustion equipment, which emit particulate matter, is effective control of the particulate emissions. The emissions limits established in the permit will ensure that the minimum stringency requirements of the MACT floor will be present at the proposed plant.

Section 112 of the Clean Air Act also recognizes the potential for stricter standards than the MACT floor. These "beyond the floor" MACT requirements apply whenever the Administrator finds that they are achievable for new or existing sources, as determined on the basis of costs, non-air quality health and environmental impacts and energy requirements. In this instance, USEPA's analysis of this question, as revealed from its proposed MACT rulemaking for utilities, suggests that a "beyond the floor" MACT is not necessary. <u>See</u>, 69 FR 4675-4677 (January 30, 2004).

217. The draft permit does not set a standard for each HAP, as required by Section 112(g) of the Clean Air Act. Coal-fired boilers emit many different HAP, including dioxin, arsenic and other metals. Other power plant permits include limits for several HAPs. For example, the

permit for the Roundup Power plant in Montana includes limits for hydrogen fluoride, hydrogen chloride, mercury, arsenic, beryllium, cadmium, chromium and manganese. PM is not a valid surrogate for non-mercury metal emissions. First, factors other than end-of-stack PM control devices also affect emissions of these HAP. Accordingly, a PM standard would not reflect the metal emission actually achieved by the relevant best performing sources. The agencies may not use a surrogate where, as here, it results in a permit that does not include standards for each HAP and does not reflect the emission levels achieved by the best performer. Second, USEPA has stated in the past that PM is not a valid surrogate for semi-volatile metals such as lead and cadmium. 64 FR 53014, 52845-52846 (Sept. 30, 1999).

Section 112(g) of the Clean Air Act does not mandate that a specific emission limit be established for each individual HAP pollutant. Indeed, USEPA has frequently recognized that a selected pollutant can be used as a surrogate for other related pollutants in establishing MACT or other technology-based limits. This is illustrated by the MACT rulemaking for non-utility boilers, where USEPA categorized a variety of HAPs into four distinct groupings (i.e., mercury, non-mercury metallic HAP, inorganic HAP and organic HAP). USEPA categorically affirmed that "…the pollutants within each group have similar characteristics and can be controlled with the same techniques. For example, non-mercury metallic HAP can be controlled with PM controls." <u>See</u>, 68 FR 1671.

In this instance, particulate controls will adequately control the heavy metals present in trace levels in coal, including beryllium. Hydrogen fluoride is chemically similar to hydrogen chloride and other acid gases. As such, hydrogen fluoride emissions will be effectively controlled through the MACT limit for hydrogen chloride and the BACT limit for SO_2. Dioxin emissions will be controlled by good combustion and the ESPs and wet ESPs that control particulate matter emissions.

218. CO may not be used as a surrogate for all organic HAPs just because CO is an indicator of good combustion. One organic HAP emitted by coal-fired boilers is dioxin. Although good combustion is a factor affecting dioxin emissions, emissions also are affected by the temperature of exhaust at different points as it passes through a boiler and the chlorine content of the materials being burned. Further, activated carbon injection is a control measure that is available to control dioxin.

USEPA in its MACT standards for industrial coal-fired boilers determined that emissions of CO are an adequate surrogate for emissions of organic HAPs. This approach is also appropriate for coal-fired utility boilers. Although activated carbon injection is a technique used for dioxin emissions at incinerators, the circumstances are different than with coal-fired boilers, e.g., incinerators have a much higher level of uncontrolled dioxin emissions. In this regard, the factors for dioxin formation identified in this comment reflect experience from municipal incinerators. For coal-fired utility boilers, activated carbon injection is a technique that is being developed for control of mercury emissions. Any results for control of the very low levels of dioxin emissions from coal-fired utility boilers are only an incidental benefit.

219. The draft permit improperly allows multiple compliance options for MACT, rather than setting a single MACT limit for each pollutant. In the absence of evidence that the three

options for mercury and two options for hydrogen chloride are equally protective of human health, it is reasonable to conclude that one will result in less emissions than the others. Particularly disturbing is the option for use of carbon injection without any limit at all. The plant must be subjected to MACT and a single stringent limit for each HAP, nothing less.

The establishment of compliance options in a case-by-case MACT determination is not improper and is consistent with USEPA's approach to MACT in its rulemaking. Setting compliance options is appropriate where a source may take different approaches to controlling emissions, by either minimizing emissions, establishing operating practices, or using specific add-on control devices if other methods are inadequate.

220. The draft permit lacks adequate monitoring to assure compliance with the limits for mercury and hydrogen chloride. The draft permit also lacks adequate testing for the mercury content of coal before it is burned. The mercury content of coal ranges between 0.08 and 0.22 ppm and substantial variation can occur even within a single mine. To assure compliance with a mercury emission limit, and in the absence of emission monitoring, the permit must require frequent sampling of the coal.

The issued permit requires continuous emissions monitoring for mercury. (The draft permit would have required continuous monitoring for mercury only if the plant were using a sorbent injection system for control of mercury emissions.) The permit also includes requirements for periodic sampling of the mercury content of the coal as needed to evaluate the performance of the control measures for mercury. On a day-to-day basis, effective control of the mercury will be addressed by the operating parameters for the boilers and their controls, as well as data from the emissions monitoring systems.

For emissions of hydrogen chloride, which is an acid gas, continuous emissions monitoring for SO_2, which is also an acid gas, also serves as a means to confirm proper control of hydrogen chloride emissions. In addition, for hydrogen chloride, the permit generally sets the "basic" compliance procedures for the boilers. These basic procedures may be enhanced or supplemented in the operating permits issued for the plant pursuant to Title V of the Clean Air Act. For pollutants like hydrogen chloride, which are emitted in sufficient quantities and for which a continuous monitoring method is not used, this would include development of and operation of the boilers in accordance with a Compliance Assurance Monitoring plan, pursuant to 40 CR Part 64.

Control Requirements for Greenhouse Gases

221. The emission rates from the proposed plant are based on a heat rate of 10,000 Btu/kW-hr. This heat rate is extremely high due to the run-of-the-mine fuel proposed for use at the plant. The low efficiency of the proposed plant results in increased emissions, especially of greenhouse gases.

As previously explained, the use of raw, run-of mine coal does not result in a high heat rate for the proposed plant. In addition, this comment reflects an incomplete analysis of the

energy efficiency of the proposed plant and its CO_2 emissions as compared to other power plants because it does not consider the small but significant energy savings from a mine-mouth plant.

222. The failure to have a more efficient plant results in increased emissions, including greenhouse gases. The CO_2 emissions from the proposed plant, estimated to be 11.5 million tons/year, could be reduced by 1.2 million tons/year by building a more efficient IGCC plant instead.

While a more efficient plant would reduce the emissions per unit of electrical output, it would only reduce the permitted emissions of the proposed plant if the size of the plant was also proportionately reduced. The fact that the development of IGCC technology is being supported by the USDOE for its potential benefits for both improved efficiency and lower emissions does not alter the current status of IGCC technology for use at the proposed plant.

223. Prairie State has offered no measures to reduce its emissions of greenhouse gases. The permit for the proposed plant should address greenhouse gases. There is general consensus of most scientists worldwide that rising levels of greenhouse gases, especially CO_2, in the atmosphere are leading to significant climate warming, shifts in precipitation patterns and rising sea levels. Power plants account for one-third of the total U.S. emissions of CO_2. Many new coal-fired power plants are proposed in Illinois at a time when CO_2 emissions should be decreasing, not increasing. The proposed plant would contribute to this trend. The record in this case does not address greenhouse gases, which are significant. If the proposed plant is built, it should be constructed to minimize CO_2 and to facilitate future capture and sequestration of CO_2. Under state law, the Illinois EPA can regulate CO_2, as it is a contaminant that, in combination with emissions from other sources, causes or tends to cause air pollution in Illinois.

Illinois law does not provide the Illinois EPA with the broad authority suggested by this comment. While emissions of greenhouse gases are a concern on a global level, emissions of CO_2 and other greenhouse gases from a single source do not satisfy, on the basis of empirical evidence or scientific judgment, the legal standard in Illinois to be considered air pollution.

Moreover, Prairie State, like the existing power plants in Illinois, is responding to the public need and demand for electricity. As such, society as a whole must take responsibility for conserving energy and pursuing energy efficiency, to reduce the emissions of greenhouse gases and other environmental impacts associated with production of electricity.

224. Prairie State should be required to have a mitigation program that offsets or minimizes its emissions. This would be a prudent step, as it is highly likely that the plant will eventually have to control its CO_2 emissions under the Clean Air Act or other federal law. CO_2 emissions could be mitigated by redesigning the plant to include: renewable energy generation, e.g., solar, wind; converting to a natural-gas plant; implementing programs to capture CO_2 in forests and agricultural soils; implementing energy efficiency, energy conservation and load management programs; or making payments to a group that would find and contract for projects that offset CO_2 emissions.

Control of CO_2 emissions requires a comprehensive approach, not a piece-meal approach for a single plant, as suggested by this comment. Application of mitigation measures for CO_2 only at a new plant would add a disincentive for the development and operation of the plant as compared to existing plants, whereas the development of new plants should be encouraged as they replace older plants that both have higher emissions and are less efficient.

225. The cost for controlling CO_2 emissions should be considered in the design of the plant. The chosen technology, pulverized coal-fired boilers, has the highest CO_2 emissions of available coal combustion technology. A supercritical pulverized coal boiler or IGCC, for example, would have lower CO_2 emissions. These benefits should be considered in the BACT analysis.

The costs for control of CO_2 emissions are not amenable to consideration during permitting in the same manner as the costs associated with control of other pollutants subject to a case-by-case BACT determination. Such costs, or more generally, the fuel efficiency of a plant, is more readily considered in a qualitative manner, as an environmental impact associated with control technologies that are otherwise being evaluated.

226. In the absence of other regulatory mechanisms, there is very substantial value added by considering the emissions of unregulated CO_2 when determining BACT for PSD pollutants, and in otherwise assessing the environmental impacts of a new coal-fired power plant. For example, the consideration of CO_2 would support consideration of cleaner, more energy-efficient process, such as IGCC, which should be about 20 % more efficient than boiler technology. Also, any newly constructed power plant will be in operation for many decades. Finally, there is a very high likelihood that mandatory CO_2 regulation will be adopted early in the lifespan of any coal-burning power plant constructed in the near future. Some utilities are already factoring the inevitability of CO_2 regulation into their business plans. The prospect of future regulatory costs must be considered in order to determine the full costs of the options for minimizing emissions of currently regulated pollutants.

Considerations of such matters in a BACT determination, to the extent suggested in this comment, are beyond the scope of the BACT determination process. Effectively, it would be an attempt to establish national policy for energy and climate change through permitting decisions for new plants, with the ultimate result that the development of new plants would be hindered and the status quo would be perpetuated.

227. The Illinois EPA must consider emissions of CO_2 in its BACT analysis. USEPA's Environmental Appeals Board (EAB) has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting BACT limits and other terms of a PSD permit, since a BACT determination is to take into account environmental impacts. A recent paper, *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review* by Gregory Foote discusses the regulatory background to support consideration of CO_2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper argues that it is entirely appropriate to consider CO_2

when evaluating environmental impacts under the new source review permit program, and the paper also provides suggested approaches for evaluating technologies in terms of CO_2 emissions.

The Illinois EPA agrees that energy efficiency is a factor that should be considered when determining BACT in certain circumstances as it would be associated with environmental impacts of the various control alternatives that are being evaluated. The Illinois EPA did consider it for the proposed plant, as loss of combustible material in coal waste is wasteful and inefficient.

228. When the Kyoto Protocol is ratified, the first compliance period is 2008 to 2012. This will put renewed pressure on the United States to address CO_2 emissions from power plants. The Illinois EPA should not ignore these developments as it considers Prairie State's proposal.

Illinois EPA cannot consider CO_2 emissions or possible impacts of the Kyoto Protocol when permitting a source. However, this is a development that could have great importance, for all of Illinois's power plants and for the residents of Illinois.

BACT - Procedures

229. USEPA's Top-down BACT Process was not properly implemented. The top-down process requires all available control technologies be ranked in descending order of effectiveness. The PSD applicant first examines the most stringent - or "top" - alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable."

The Illinois EPA required the requisite top-down analysis by Prairie State. In its October 2002, Updated Permit Application, Prairie State ranked the available technologies and appropriately selected BACT in accordance with the regulations and the guidance in the NSR Manual. The NSR Manual provides guidance on what is an "available" technology. An "available" technology is one that "can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term . . . technologies in the pilot scale testing stages of development would not be considered available for BACT review." NSR Manual, p. B-17 through B-18. As recently as July 2004, Prairie State supplemented its BACT analysis with additional information on developing control technologies.

230. While Prairie State selected the top technology based on control efficiency, it arbitrarily selected BACT emission limits that did not represent the maximum degree of reduction. BACT is an emission limit, not the top technology based on removal efficiency. Prairie State and the Illinois EPA failed to select a limit that represents the maximum degree of reduction for any of the PSD pollutants and failed to provide any justification for not selecting the lowest emission rate.

Prairie State provided the basis of its selected BACT limits. In addition, the Illinois EPA appropriately established BACT considering the maximum degree of reduction for the control technologies selected as BACT. For this purpose, appropriate safety factors were applied to the actual emission rates achieved in practice, as must occur in the setting of BACT limits, so that normal variation in the performance of a control technology when properly maintained and operated does not result in non-compliance. Because of the need to address this "normal variability," one aspect of this limit setting process was consideration of the limits set in other permits for new power plants, as such limits also reflect determinations of the appropriate limits to be accompany different control technology.

231. After selecting the top technology based on a range of performance levels, the BACT analysis arbitrarily selects an emission limit, without considering the most effective performance level. The control method selected has a wide range of emission performance levels, e.g., SCR can remove as little as 30% to over 90% of the NOx. It is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a justification to do otherwise.

As this comment notes, control technology can operate over a wide range of performance levels. *See,* NSR Manual, p. B. 23. To determine what was achievable for the proposed plant, in practice, Prairie State consulted the RACT/BACT/LAER Clearinghouse, other permits, draft permits and pending applications. BACT limits for different pollutants were appropriately selected.

232. Prairie State and the Illinois EPA apparently relied solely on the USEPA's RACT/BACT/LAER Clearinghouse (RBLC) and a selection of permits and applications not included in the RBLC to establish BACT limits. The BACT research was incomplete because the RBLC may be incomplete and out of date. The NSR Manual recommends that other sources be consulted. The application and the Illinois EPA's Project Summary contain no evidence that these additional sources were consulted. In addition, the cutoff data for a BACT determination is the date of issue of the permit.

Prairie State's analysis of the potential BACT emission limits was appropriate. As necessary to support the BACT determination, the RBLC was consulted. Prairie State submitted its last BACT Table with limits in permits, draft permits and pending applications for other coal-fired power plants, updated through July 12, 2004. The Illinois EPA also conducted its own independent review of information for the performance of emission controls. These efforts included sending a staff member to the *Combined Power Plant Air Pollutant Control Mega Symposium*, in September 2004, to be updated on the most current developments. These efforts continued until the date that the permit was issued, when the BACT determination was finalized.

233. The BACT analysis includes two tables: (1) Summary for Recently Proposed or Permitted PC Sources (App., Table C.5-2) and (2) BACT Comparison of New, Proposed and Permitted Coal Fired Power Plant Emission Limits. ("BACT Summary Table," 10/10/02).

The application and the summary provide no specific reason(s) for eliminating the lowest limits on these tables as BACT for any particular pollutant or source. The footnotes suggest that pollutant inter-relationships as a basis for eliminating the limit as BACT. Denial is not appropriate without an evaluation of the inter-relationships in the top-down process and documenting the basis for rejection.

Negative inter-relationships between control of different pollutants ultimately did not play a significant role in the Illinois EPA's determination of BACT, except for the interaction between NOx and CO emissions, where preference was given to control of NOx given its greater environmental significance. Even then, the Illinois EPA does not believe that the emission limit for CO was significantly impacted by such considerations.

234. Increased reductions of NOx by an SCR can increase emissions of sulfuric acid mist if NOx is reduced by using more catalyst in the SCR. However, this effect could be avoided by selecting a catalyst with a low SO_2 to SO_3 conversion rate or by increasing the sulfuric acid mist removal in the downstream wet ESP. SCR catalysts are available with a range of conversion rates, from 0.1% to 2% or more. The potential increase in sulfuric acid mist due to a reduction in NOx is a design and cost issue, not a technical reason to eliminate any particular NOx limit or NOx control efficiency.

Formation of sulfuric acid mist by an SCR can be effectively addressed by use of a wet ESP following the SCR, as indicated by this comment. Beyond this, the design of an SCR is not as simple or one-dimensional as suggested by this comment. First, a catalyst with high conversion of SO_2 to SO_3 is likely beneficial for control of mercury emissions, as such a catalyst would also facilitate conversion of mercury to oxidized forms which are effectively controlled by the SO_2 scrubber. Second, SCR systems and their catalysts function in particular temperature ranges. Thus, the design of an SCR must be integrated with the overall design of the boiler to maintain both the effectiveness of the SCR and the thermal efficiency of the boiler. Using a less reactive catalyst, as suggested by this comment, generally requires some other compensatory action, such as operating the SCR at higher temperatures or use of more ammonia. Higher temperatures may shift the thermal profile through the boiler, leading to lower energy efficiency, i.e., higher emissions per unit of output, or the need for other adjustments to the design of the boilers. Likewise, use of more ammonia may have consequences for the design of other features of the boiler such as the air preheater. While such interactions can be addressed in the design of a boiler and SCR system, as indicated by this comment, there are technical limits on the extent of such adaptations.

235. The reduction of boiler outlet NOx with low-NOx combustion techniques can result in increases in boiler outlet CO, depending upon combustion conditions and the type of low NOx techniques used. However, CO is generally of less concern than NOx because it is a weak ozone precursor. NOx reductions that increase CO are generally considered to be a net benefit.

The observations in this comment about the interaction of NOx and CO emissions in large boilers are generally true. However, it is also worth noting that low-NOx combustion techniques for large boilers are designed to reduce NOx emissions without accompanying,

significant increases in CO emissions. This is important as low CO emissions are indicative of good combustion in a boiler, and high levels of CO emissions are associated with emissions of incomplete combustion products and loss of thermal efficiency in a boiler. For boilers, with their elevated stacks, these related phenomena associated with high CO emissions are of greater concern than the CO emissions themselves, as the air quality standards for CO are orders of magnitude higher than the standards for other criteria air pollutants.

236. The BACT analysis eliminated lower emission rates because the boiler design or coal supply was not similar. These reasons are inconsistent with the top-down process, which requires that technology transfer be considered. The BACT analysis contains no demonstration that limits achieved on similar boilers and fuels would not be achievable for Prairie State. The achievability of emission limits for different types of boilers or different types of coals is normally addressed as a design issue and evaluated in the BACT analysis in the economic analysis. For example, low NOx limits achieved with low sulfur, low ash sub-bituminous coals can also be achieved with high sulfur, high ash bituminous coals, such as those proposed for Prairie State, by selecting a suitable SCR catalyst, proper design of downstream control devices, and appropriate operating conditions.

The emission rates and limits that were generally "eliminated" because of the coal supply for the proposed plant, as compared to the coal supply for other plants, were SO_2 emission rates expressed in lb/mmBtu. To address the critical role of the coal sulfur content in the BACT determination for SO_2 for the proposed coal-fired boilers, a decision was made to include a BACT limit in the issued permit that directly addresses SO_2 removal efficiency. When expressed in terms of control efficiency, the control of SO_2 emissions required of the proposed plant is higher than that required of other new power plants.

In particular, the SO_2 control efficiency that is effectively being required for Mid-American Energy's Unit 4 in Council Bluffs, Iowa, which is designed for western, Powder River Basin coal, is less than 90 percent (1.0-0.1/0.625 = 0.84). For Wisconsin Electric's Elm Road Generating Station, which is designed for Pittsburgh No. 8 coal, the effective control efficiency is nominally 96.25 percent (1.0-0.15/4.0 = 0.9625). For Long View Power, the calculated control efficiency required to be achieved is nominally 97.63 percent (1.0-0.095/4.0 = 0.9763).

237. An SCR for a high sulfur, high ash coal could achieve the same NOx emission rate as a low sulfur, low ash coal by selecting a catalyst with a low SO_2 to SO_3 conversion rate and a high resistance to erosion and by using soot blowing. These design considerations may increase capital and operating costs compared to the low sulfur, low ash case. Alternatively, a low SO_2 limit achieved on a CFB boiler could also be achieved on a pulverized coal boiler by increasing the efficiency of the SO_2 scrubber and/or by mixing lime or limestone with the coal or by injecting them into the boiler.

The Illinois EPA generally concurs with this comment as it addresses NOx emissions. In this regard, the BACT limit for NOx emissions set in the issued permit is 0.07 lb/mmBtu, which is identical to the BACT limit set for other new power plants that burn a range of different coals. The Illinois EPA must differ with the remarks related to CFB boilers, as they suggest that CFB boilers have inherently lower SO_2 emissions than pulverized coal boilers. CFB

boilers differ from pulverized coal boilers as a substantial reduction in SO_2 emissions can be accomplished by introducing limestone into the bed of the boiler rather than by controlling all SO_2 emissions by scrubbing. However, the effectiveness of bed injection is not boundless, as the amount of limestone in the bed has operational consequences for a CFB boiler. As a practical matter, to efficiently achieve the level of overall control of SO_2 emissions being required of the coal-fired boilers at the proposed plant, a CFB boiler would also have to be equipped with add-on control technology to supplement the control provided by bed injection. In addition, this comment disregards the performance of CFB boilers for NOx, which is not as effective as that of pulverized coal boilers equipped with add-on SCR, as is occurring at the proposed plant.

238. The BACT analysis should have considered the health impacts of primary and secondary releases of particulate matter. If this evaluation had been undertaken, Prairie State would not have been able to justify its plans for burning unwashed coal in the pulverized coal boiler. If health care costs are used both in adopting rules and in enforcement, then such data should also be considered in permitting decisions under the environmental considerations of the BACT analysis.

Prairie State is employing a combination of technologies to control emissions. The air emission control equipment for Prairie State is very efficient and is designed to handle emissions from combustion of unwashed high sulfur, high ash coal. In so doing, the proposed plant will comply with the applicable requirement to protect air quality and public health. There is no regulatory requirement for considering health impacts in the BACT analysis during permitting. The fact that such information is used in certain rulemakings, which deal with broad categories of sources, does not justify the inclusion of such information in the permitting of a single proposed source.

In addition, Prairie State evaluated coal washing in its top-down BACT analysis. The analysis showed that coal washing would result in only a 20% to 30 % reduction in the sulfur content of the coal supply. This would be accompanied by generation of significant quantities of solid waste and coal-water slurry mixture. These would have to be managed through disposal or treatment. Based on all of the foregoing and Prairie State's analysis that coal washing had excessive economic and energy costs, coal washing offers little benefit.

239. Due to the similarities of the Baldwin plant and the proposed plant, USEPA and USDOJ's health impact data from the Baldwin lawsuit provide a resource to accurately estimate the health impacts from the proposed plant. Total deaths due to Baldwin in 1996 were estimated at 508 (393 due to sulfate and 115 due to nitrates). Scaling for differences in emissions, this information can be used to estimate Prairie State's projected impacts. Based on Prairie State's potential annual emissions, this information yields 26 premature deaths attributable to Prairie State's emissions.

In addition, Levy and Spengler examined health impacts of the proposed Elm Road plant near the Illinois border in Wisconsin, which would have similar but lower emission levels than the proposed plant. The findings from both the Baldwin power plant NSR evaluation and the Levy and Spengler testimony at Elm Road agree closely that the likely impact of a

Midwestern plant with the size and emission characteristics of the proposed plant would be approximately 25 to 30 deaths per year. The value of avoiding these deaths is greater than any cost increase from any other BACT option.

Prairie State is employing a combination of technologies to control emissions. In so doing, the proposed plant will comply with all applicable state and federal regulations that protect air quality and public health. The modeling evaluation shows that the maximum concentrations of potential emissions from the plant are well within the applicable ambient standards. Given the conservative way that this evaluation is conducted, it is protective of people in the vicinity of the proposed plant, including the residents of Washington County. Nor can it be ignored that clean electricity from coal improves the nation's health by making affordable electricity available thereby increasing the quality of life and lifespan. Moreover, the specific data cited by the comments shows how well controlled the proposed plant is, with impacts that are a fraction of those of existing plants.

240. Levy and Spengler examined health impacts of the proposed Elm Road plant in Wisconsin near the Illinois border, which would have similar but lower emission levels than the proposed plant. They testified before the Wisconsin Public Service Commission that morbidity and mortality linked to the Elm Road plant's emissions would cost over $3 billion in present dollars over the expected 45 year-life of the units. Most of this damage is related to the projected 22 deaths/year that are linked to the direct PM emissions and SO_2 and NOx emissions of the two pulverized coal units, which would be greatly reduced if IGCC technology were used instead. The estimated benefit of reduced air emissions from IGCC technology equate to approximately $7.80 in avoided health damage per MW-hour of plant operation, which dwarfs any short-term incremental cost of generating electricity from IGCC instead of pulverized coal boilers. This is consistent with findings by Robert Williams of Princeton. In a 2000 report published by the United Nations, Williams estimated the incremental health benefits of going from a new conventional coal plant which meets conventional BACT standards to an IGCC plant at around $5/MW-hr.

This comment reaches a false conclusion. First, the comment assumes that a power plant does not perform any useful function, i.e., human health and well-being are unaffected by the availability of electricity and society could continue to function without an affordable and reliable source of electric power. Second, it also ignores the health benefits that may accrue from a new power plant comparing such a plant to any existing plant that it replaces. This is particularly relevant as comparison between the health impacts of an IGCC power plant and a pulverized coal power plant is only a theoretical exercise if the IGCC plant could not be developed. Accordingly, a more thorough evaluation could also identify a significant benefit to public health from the proposed plant. However, as explained in the response to other comments, the PSD rules do not require that such a comprehensive evaluation of the effect of power plants emissions must be conducted to determine BACT, which as matter of rule focuses on the emission reductions that will result from use of different control alternatives and the costs and environmental impacts associated with those alternatives.

241. It appears that limits in permits for certain new power plants were eliminated from the BACT analysis. For example, the filterable PM/PM10 of 0.012 lb/mmBtu and the NOx limit

of 0.05 lb/mmBtu limit were not included in the BACT analysis. The only apparent reason is that they were proposed limits, which is not a valid reason for eliminating a potentially achievable limit from a BACT analysis. A proposed limit represents an applicant's or a permitting agency's judgment that a limit is feasible for a similar source. This should trigger an investigation of whether the same limit is achievable for the source under review. If the limit is not achievable for the source under review, the reasons must be documented in the record. The BACT analysis contains no support for why lower proposed limits are not applicable to the proposed plant.

BACT is a case-by-case determination and a permitting authority is not bound by the judgment, or lack or judgment, of applicants for other projects and other permitting authorities. In this regard, some doubt applies to any permit limit until the source is actually built and compliance with such limit is actually confirmed in practice. This is significant as limits set as BACT should not be set at levels that are not achievable in practice, such that normal variability in the performance of a source threatens or results in noncompliance, even when the source is properly operated and maintained.

242. The draft permit does not represent BACT. Furthermore, possible grounds for overturning a BACT decision include an inappropriate review (BACT procedures not correctly followed), an incomplete review (BACT decisions not correctly justified), or a review based on false or misleading information. USEPA's 1990 New Source Review Workshop Manual (NSR Manual) details the necessary process for a "top down" BACT review. This five-step top-down BACT process must be conducted to ensure that a valid BACT determination has been made. As described below, Prairie State's BACT analysis is erroneous. Also, the BACT analysis is dated October 2002, thus it is clearly stale. USEPA guidance is clear that the permitting agency and the applicant are under an ongoing duty until the date of final permit issuance to update the BACT analysis as new information becomes available. Because these comments, and comments provided by others indicate there are numerous other permits and emission rates that are being achieved at existing coal-burning power plants – and not yet considered as part of the Prairie State BACT analysis – its BACT analysis must be significantly revised and updated.

The proposed BACT determination in the draft permit is not the BACT determination for the proposed plant. The BACT determination is contained in the issued permit, and was reached as the result of a BACT analysis that was not finally completed until review of the public comments, immediately prior to the final permit decision.

243. A permit may require that only a certain fuel be used when that fuel has been selected at the end of an appropriate BACT/MACT determination. The use of high-sulfur Illinois coal from Prairie State's proposed coal mine has not yet met this test.

The Illinois EPA must disagree with this comment, as it is stated. In the absence of an appropriate BACT demonstration, the operation of a proposed plant or emission unit may be restricted to the cleanest fuel that is available. However, for the proposed plant, an appropriate BACT evaluation has been performed for high-sulfur Illinois coal and BACT has been appropriately set for the use of such coal at the proposed mine-mouth power plant.

Moreover, as previously discussed, the selected coal supply for the proposed plant is an intrinsic element of the proposed mine-mouth power plant.

244. The BACT limits for the proposed plant should be based on electricity output and expressed in lb/MW-hr. This would provide a more honest assessment of the amount of emissions per unit of desired outcome. USEPA recently proposed output-based in its proposing rules for emissions of mercury from new power plants. As with its 1998 rulemaking under 40 CFR 60, Subpart Da, USEPA pointed out that standards set on an output basis created an incentive for sources to operate more efficiently. In short, a more efficient process that produces lower emissions per unit of fuel combusted or materials processed is a form of "inherently lower-polluting" process.

An "output based" approach is not possible as a general matter for purposes of BACT, nor is it necessary or even desirable. It is not possible because the historic data for performance of existing power plants in terms of net electrical output is not readily available for the purpose of setting BACT limits. For a plant subject to BACT, actual emission data in terms of net output is also not readily available nor would such data be instantaneously available with emission monitoring data. An output-based approach is not needed because BACT limits are set for a specific project. Finally, an output based approach to BACT is only desirable if one believes that improvements in plant energy efficiency (which will come with future projects as technology evolves) should not be accompanied by reductions in the rates of emissions

245. The draft permit's restriction on using coal from other sources is illusory. It would allow the plant to burn up to 5 percent "other" coal, yet Prairie State's BACT and MACT analysis do not consider the air quality benefits of burning 5 % low sulfur coal (or 5 % high sulfur petroleum coke). Second, the restriction would not apply during interruption in the operation of the mine.

The issued permit includes changes that respond to the issues raised by this comment. First, the amount of other fuel material that may be burned in the coal-fired boilers has been eliminated. Second, the restriction has been reworked so that it would continue to apply during interruptions in the mine-mouth coal supply, as was always intended.

BACT – Cooling Tower

246. The BACT analysis must consider dry cooling as an alternative to the wet cooling towers planned for the proposed plant. Cooling towers have significant emission of PM10 and dry cooling is an available technology to eliminate these emissions. In addition, dry-cooling would eliminate any controversy over access to water from the Kaskaskia River, the planned source of the cooling water, as dry cooling, or some hybrid thereof, would greater reduce the plant's water consumption. For the proposed Weston Unit 4 in Wisconsin, dry cooling is estimated to reduce overall water consumption by between 95 to 98 percent. (See Attachment 5.) Dry cooling would also lower the costs for water intake structures and raw water treatment systems.

Dry cooling is feasible. It has been used on large coal-fired power plants for over 25 years. The 330 MW Wyodak plant in Wyoming has operated with dry cooling for over 25 years. The 4,000 MW Matimba plant in South Africa, the largest coal fired power plant in the world using dry cooling, has operated for over 10 years. Over the last three years in New Mexico, a number of companies have proposed new coal-fired power plants with dry cooling to minimize water use.

These comments do not provide an adequate basis to require dry cooling for the proposed plant. Dry cooling is certainly a demonstrated technology. However, use of dry cooling in areas where water resources are limited and the relative humidity is low (e.g., weather conditions in which wet cooling would consume comparatively more water), does not demonstrate that dry cooling is appropriate for the proposed plant. This is because of the additional power required by dry cooling and its effect on the energy efficiency of the proposed plant, which are overlooked by this comment. The additional power required for dry cooling would act to increase emissions of pollutants other than PM. If dry cooling would lower the plant's efficiency by more than a few percent, the net effect of using dry cooling would also be to increase emissions of PM, as well as other pollutants. As such, dry cooling is a less-effective technology as related to emissions because its use would act to increase overall emissions of pollutants and CO_2 from the plant. Impacts of the plant related to water are appropriately addressed through the regulatory program that addresses such matters. Also, as the lower Kaskaskia River is managed for barge traffic and is supplied by Shelbyville Lake and Carlyle Lake, the proposed plant would not change the character of the Kaskaskia River. Accordingly, dry cooling has been readily evaluated. While technically feasible, it is not appropriate to be required of the proposed plant.

247. Other benefits of dry cooling would be elimination of aesthetic issues related to visible plumes and elimination of highway safety concerns due to fogging and icing. In 1995, Cedar Falls Utilities, Streeter Station Unit 7A, a 36 MW pulverized coal unit in Iowa, was retrofit with dry cooling due to highway safety concerns caused by the tower plume in winter. The use of dry cooling on pulverized coal fired power plants is well established.

The use of dry cooling on large power plants in the Midwest is not well established. The use of dry cooling on a small municipal power plant that is located in an urban area near state highways is not applicable to the circumstances of the proposed plant. Dry cooling would also present its own esthetic issues from the additional structure for the dry cooling tower.

248. Wet cooling can result in significant public health impacts in the surrounding community. For example, the Cooling Technology Institute advises permitting authorities should assume that any cooling tower system harbors the Legionella bacteria. Legionella bacteria emitted with the PM10 emissions in cooling tower drift would be hazardous and need to be addressed in the application. The most direct solution to concerns about Legionella bacteria would be to use dry cooling.

Wet cooling towers have not been identified as a general threat to public health, nor does the observation made by the Cooling Tower Institute demonstrate that cooling towers pose such a

threat. The Cooling Tower Institute provided its advice in a broader context addressing proper design and operation of wet cooling towers. In this context, control of the growth and buildup of algae and bacteria is an aspect of proper operation of any wet cooling tower and can be readily accomplished by simpler means than use of dry cooling.

BACT – Other Emission Units

249. The mine and power plant are a single source and must be permitted as one. In its application, Prairie State asserts that the mine and power plant are a single source for purposes of PSD permitting. The draft permit states that "the power plant shall operate as a mine-mouth plant, using coal delivered by conveyor belt directly from the mining facility or facilities as the principal source of coal for the two coal boilers." However, the application and draft permit do not include a BACT analysis for the mine operations or any modeling for associated emission sources such as the mine vents. This is required.

The application and draft permit do address the mining operations. BACT is set and modeling was conducted for appropriate emission points. In this regard, the ventilation air from a mine is similar to the building ventilation vents from a manufacturing facility, office complex or school, except that it is regulated by the Mine Safety and Health Administration (MSHA), rather than by the Occupational Safety and Health Administration (OSHA).

250. BACT for bulk material handling and storage operations is flawed. The draft permit would not require that the transfer belt and coal-storage piles have to be covered or enclosed. This does not represent BACT. The permit for the proposed Indeck-Elwood plant requires enclosure. Prairie State's BACT analysis must consider the same. This may well be addressed through a thorough and lawful BACT analysis that includes enclosing all associated coal-handling facilities.

The draft permit requires effective control of emissions from the transfer belt and storage piles, consistent with BACT. As a general matter, the provisions for similar operations at the proposed Indeck-Elwood plant are not governing for the proposed plant, as the circumstances of that plant are significantly different from those of the proposed plant. The Indeck-Elwood plant is located on a relatively small piece of property, immediately adjacent to the Midewin National Tallgrass Prairie and a rail-to truck intermodal center at which new motor vehicles cars are transferred from railcars to transport trucks for distribution throughout the greater Chicago area. Because of general concerns expressed by these neighboring facilities, Indeck committed to the control measures that it did, as reflected in its permit. These circumstances are not present for the proposed plant, which is located in a rural area, on a large piece of property that provides an ample buffer for its neighbors from any nuisance impacts from material handling operations.

However, with respect to the transfer belt at the proposed plant, the provisions of the issued permit have been changed to make clear that the transfer belt must be covered or enclosed, as was always intended. As part of this clarification, the provisions for the storage piles and

associated operations at the proposed plant were separated from the provisions for the transfer belt. Appropriate performance criteria were also included for the two types of units.

In addition, the storage of coal and limestone in structures or buildings is not appropriate as the proposed plant has been sited and is being developed to allow open storage. In this regard, the magnitude of the cost and cost-effectiveness of requiring the proposed plant to store coal in structures or buildings is readily assessed and identified as excessive. The area occupied by the various storage piles at the plant is over 20 acres, so that the cost of enclosing these piles would be in excess of $5 million. Even after amortization of this cost, the annual cost-effectiveness of such buildings for further control of particulate matter would be in excess of $25,000/ton.

251. BACT for the diesel engines is not a maximum fuel sulfur content of 0.05 percent, by weight. Natural gas and ultra-low sulfur diesel with 15 ppm to 30 ppm sulfur is currently available for the plant and has been required in many permits for similar power plant engines. Natural gas will already be available during startup of the coal boilers. Low-sulfur diesel was established as BACT for the Elm Road plant in Wisconsin. Further, USEPA has adopted rules for diesel oil that will reduce sulfur content even further. The BACT analysis for diesel engines must be redone to consider natural gas and ultra-low sulfur diesel.

The issued permit requires ultra low sulfur fuel oil to be used in engines, as it will be available when the plant begins operation. While natural gas is suitable for certain other units at the plant, such as the auxiliary boiler, it is not appropriate for the diesel engines, which are associated with emergency fire pumps. In particular, natural gas cannot be readily stored at the plant to provide the on-site storage of fuel that is needed to assure that the diesel engines have a dependable fuel supply and can operate whenever their services are needed.

Pre-Construction Monitoring

252. Why hasn't pre-construction monitoring been performed for the proposed plant to determine the actual levels of air quality in the region? The Illinois EPA has not required such monitoring even though it is required under the PSD and NSR programs to determine whether this project should be permitted. In order to conduct an adequate air quality analysis under the PSD program, it is imperative to have good data of current site air quality. This is especially so for the criteria pollutants, SO_2, PM, CO, and ozone. Such data could also be useful for HAPs, especially for a new coal-fired power plant, like the proposed plant.

Prairie State has not performed pre-construction monitoring because the State of Illinois' existing ambient monitoring stations, which collect data on a continuing basis, year after year, were able to provide the necessary information on current air quality to support the air quality analyses for the proposed plant. Given these circumstances, the Illinois EPA formally determined that Prairie State could satisfy the applicable requirements of the PSD program for pre-construction monitoring data by appropriate use of data already available from Illinois' existing monitoring network.

Although not relevant to pre-construction monitoring under the PSD program, some of the state's existing monitoring stations collect air quality data for certain HAPs, in addition to collecting data for criteria air pollutants.

253. A major source like the proposed plant must conduct ambient monitoring for all criteria pollutants. The NSR Manual specifies that pre-construction monitoring data must be collected for up to a year prior to submittal of an application if estimated air quality impacts exceed certain thresholds. It is clear that the proposed plant exceeds these limits. The absence of such data throws into question the air quality analyses that have been conducted for the proposed plant. Prairie State should have been required to undertake pre-construction monitoring for ozone, PM, SO_2, CO, and lead.

The PSD rules do not require that an applicant perform ambient monitoring prior to submittal of an application if adequate monitoring data is already available to perform the required air quality analyses for a proposed project. As explained by USEPA in more detail in the NSR Manual, the PSD rules require an applicant "to provide an ambient air quality analysis that *may* include pre-application monitoring data, and in some instances post-construction monitoring data, for any pollutant proposed to be emitted in significant amounts." The NSR Manual describes the circumstances in which such monitoring may be required, or waived, at the discretion of the permitting authority. Even where such monitoring data is required, an applicant has the option of requesting that it be allowed to use existing monitoring data that is representative of conditions expected in the impact area of the proposed source. This is what occurred for the proposed plant. Prairie State requested that the Illinois EPA approve the use of existing monitoring data to satisfy the requirements of the PSD program for pre-application monitoring data for ozone and other pollutants. The Illinois EPA approved Prairie State's requests because the selection and use of this existing ambient monitoring data contained in Prairie State's air quality analyses adequately represented, or conservatively overstated, levels of existing background air quality in the area surrounding the proposed plant.

254. Pre-construction monitoring is especially critical for the proposed plant since adjoining counties recently have been designated as nonattainment for the ozone (8-hour average) and or shortly will be designated nonattainment for the PM2.5 NAAQS.

These actions confirm the adequacy of the State of Illinois' existing ambient monitoring for the region, as these designations of nonattainment and attainment were made based on data from the existing monitoring network.

255. The Clean Air Act says that a source may not cause or contribute to a violation of any NAAQS. Clearly, given its proximity to ozone (8-hour) and PM2.5 nonattainment areas, the proposed plant will contribute to existing violations of both these NAAQS. There is an existing ozone monitoring station in Randolph County that Prairie State claims is representative of its site. In 2002, this station monitored a violation of the 8 hour ozone standard. Prairie State must rely on this data.

This comment greatly simplifies the applicable requirements that apply under the Clean Air

Act with respect to protection of air quality. As is clear from their name, the federal PSD rules are intended to prevent significant deterioration of air quality, not to prevent any deterioration of air quality. A key test under the PSD rules is whether the effect of a proposed major source should be considered "significant" or "excessive." The air quality analyses conducted for the proposed plant show that its impacts would not be excessive.

Similarly, the comment fails to consider the context in which exceedances of the 8-hour ozone NAAQS were measured in 2002 at the monitoring station in Randolph County. These exceedances reflected the effect of St. Louis on Randolph County, under weather conditions in which Randolph County was downwind from the Greater St. Louis area. They do not reflect the effect of local sources in Randolph County on ozone air quality. Accordingly, the exceedances would likely have occurred even if there were no local sources in Randolph County. In addition, a review of the ambient data from this station for the period from 2002 to 2004 shows attainment of the 8-hour ozone standard, with peak values of 77 and 69 ppb measured in 2003 and 2004 respectively.

256. The air quality analysis must include preconstruction monitoring for ozone. The proposed plant has a potential to emit of over 100 tons per year of VOM. Therefore, Prairie State is required to gather pre-construction ozone data. Illinois EPA appears to have arbitrarily waived the requirement for pre-construction ozone monitoring. Even if the failure to conduct preconstruction monitoring is acceptable, the permit must require post-construction ozone monitoring.

Illinois' existing ambient monitoring network is adequate for ozone. There are eight monitoring stations for ozone in the Greater St. Louis Area and Randolph County.

257. Monitoring and the assessment of potential impacts must occur prior to construction and granting of a permit. Condition 1.7 of the draft permit would only require "post construction monitoring" to be up and running one year before the start up of the boiler.

The PSD program allows a permitting authority to require post-construction ambient monitoring when there are valid reasons for such monitoring (40 CFR 52.21(m)(2)). In this case, post-construction monitoring for certain pollutants will aid the Illinois EPA to better account for the proposed plant in the development of the PM2.5 attainment demonstration for the Greater St. Louis area. The limited ambient data for background levels of PM2.5 and precursor ammonia emissions southeast of St. Louis might otherwise restrict the precision of the modeling conducted for the attainment demonstration. Accordingly, the Illinois EPA has required Prairie State to perform appropriate "post-construction monitoring" to assist the Illinois EPA in its attainment planning for PM2.5 air quality. This monitoring data will also support evaluation of the impact of sources in southwestern Illinois on the Mingo Wilderness Area.

258. To verify proper operation of the proposed plant, the permit should require Prairie State to perform ambient monitoring of PM and mercury that includes stations immediately downwind, at the site border, and one-mile from the site border.

Ambient monitoring, as requested by this comment, would not be an effective method to verify proper operation of the proposed plant. This is because such monitoring would only address the impact of the plant under certain conditions of wind direction and wind speed, and even then would do so after the plant's emissions have been diluted in the atmosphere and mixed with background levels of pollutants already in the atmosphere. As a result, the impact of the plant might not even be identifiable and distinguishing improper operation of the plant would certainly be problematic. Proper operation of the plant is best verified directly, that is, by monitoring emissions from the boilers in the stack before they are released to the atmosphere, as has been required.

Extent of Air Quality Analysis

259. Prairie State's SO_2 and PM10 increment modeling must include the Baldwin power plant as an increment consuming source. The USEPA is currently suing Dynegy for making major modifications at the Baldwin plant without obtaining PSD permits. The State of Illinois has joined in as a plaintiff in this lawsuit. However, Prairie State did not include the Baldwin plant in its SO_2 and PM10 modeling for the Class II increment, treating the plant as if it were not an increment consuming source. The Illinois EPA must have a consistent position on the Baldwin plant. As Illinois has concluded that major modifications occurred at the Baldwin plant, this means that the Illinois EPA must require the plant to be treated as an increment consuming source and Prairie State should be required to re-do its SO_2 and PM10 increment modeling to include Baldwin.

This modeling was performed properly. As a legal matter, until the USEPA's lawsuit was resolved and USEPA prevailed through a court order or settlement, the potential consequences of the alleged PSD violations at the Baldwin plant could not be considered "applicable requirements." To the extent that the increment modeling for the proposed plant had been required to include the Baldwin plant as an increment consuming source, such action would then certainly have been challenged by Dynegy. If Prairie State had been allowed to rely on the Baldwin lawsuit in the modeling to increase the amount of available increment, that also would likely have been challenged. In either case, the parties would have almost certainly prevailed on appeal because the increment modeling for the proposed plant would have been premised upon "un-adjudicated" violations.

In addition, the lawsuit is being settled in a way that does not characterize the plant as an increment consuming source. This was a likely outcome. In particular, separate from the alleged modifications at Baldwin, other changes have also occurred at the Baldwin plant that have acted to decrease emissions. In addition, further emission decreases will occur from additional improvements in emission control required at Baldwin.

260. Modeling must also be performed to demonstrate that the proposed plant will not cause or contribute to a violation of the PM2.5 NAAQS for the same reasons that Prairie State must conduct modeling to address the 8 hour ozone NAAQS. It is not reasonable to expect that a permit will be issued for the plant before the PM2.5 designations become effective. PM 2.5

modeling is especially important because the St. Louis metropolitan area, the eastern border of which is less than two miles from the site of the proposed plant, is predicted to be nonattainment for the PM2.5 NAAQS even if the new federal Clean Air Interstate Rule (CAIR) is put into effect.

Modeling specifically for PM2.5 is not required under the PSD rules because the proposed plant is highly unlikely, by itself, to have a significant impact on PM2.5 air quality. Moreover, modeling cannot be carried out in a meaningful way at this time as it is presently not possible to precisely predict future PM2.5 air quality that will exist when the plant begins operation, given improvements in air quality that are expected in the intervening years and lack of USEPA guidance on how such an analysis should be performed. Modeling was conducted for the proposed plant for the various pollutants that play a role in air quality for PM2.5, i.e., particulate matter (PM10), SO_2 and NOx. In addition, as further discussed later, the Illinois EPA assessed PM2.5 emissions from the proposed plant that is available and by considering air quality modeling for the proposed plant's existing ambient monitoring data.

The Illinois EPA is also proceeding in an appropriate manner to address the new PM2.5 NAAQS. The Illinois EPA recommended, and USEPA concurred, that portions of the Metro-East area, including counties near the site of the proposed plant should be designated as nonattainment for PM2.5. However, these nonattainment areas do not include Washington County. They include Baldwin Township in Randolph County, not the entirety of Randolph County. USEPA has taken this action for Randolph County because the existing Baldwin power plant is located in Baldwin Township, not because the PM2.5 NAAQS standards are exceeded in Baldwin Township. (Indeed, the monitoring station in Randolph County is among the monitoring stations in Illinois that measure the lowest (best) air quality for PM2.5 in Illinois.) Instead, USEPA is taking this action and similar actions across the country because existing, large coal-fired power plants that are located near areas in which the PM2.5 NAAQS are actually exceeded, like the Baldwin power plant, may contribute to those exceedances of the PM2.5 NAAQS.

However, USEPA has not yet released necessary, detailed guidance for the implementation of the PM2.5 NAAQS. Appropriate methodology and procedures for performance of PM2.5 air quality analyses have not yet been established by USEPA to support development of State Implementation Plans for PM2.5. This is essential because PM2.5, like ozone, poses concerns for emissions and air quality on a regional scale and, to a significant degree, is formed in the atmosphere from reactions of precursor compounds. USEPA is also under an obligation to develop the necessary procedures for performance of project-specific analysis for PM2.5, as it did for the 1-hour ozone NAAQS. Still, because of concerns about the potential role of the proposed plant in PM2.5 air quality, the Illinois EPA is requiring Prairie State to conduct post-construction monitoring related to PM2.5. Additional monitoring data for background air quality levels southeast of St. Louis should help the Illinois EPA and Missouri DNR to perform better modeling to develop a PM2.5 attainment plan for the Greater St. Louis Area. This attainment plan will have to include additional "local" controls beyond CAIR as necessary for the greater St. Louis area to comply with the PM2.5 NAAQS.

261. USEPA has failed to comply with the Executive Order requiring protection of children from

health risks. Pursuant to Executive Order, *Protection of Children from Environmental Health Risks and Safety Risk*, (April. 21, 1997), before the proposed plant is approved, USEPA must conduct an assessment of its emissions to address any disproportionate health risks to children. This is because the plant would place children disproportionately at risk in at least three ways. First, more mercury emissions means more contaminated fish. The unborn and young children are at greatest risk of harm from mercury. Second, the proposal would emit SO_2 and PM10, deteriorating SO_2 and PM10 air quality. Thirdly, children are at greatest risk from the emissions of HAPs.

Both the USEPA and Illinois EPA are concerned about the potential for disproportionate health risks to children and attempt to address those potential risks in their various programs. For example, as noted in the comment, concerns about mercury contamination and programs to address such contamination and control mercury emissions are driven by the need to protect children, not adult men or women. NAAQS are set at stringent levels as needed to protect sensitive sectors of the population, notably the young, as well as the elderly and those already suffering from respiratory disease, as appropriate based on the potential effects of exposure to a pollutant. NAAQS are not set just at the higher, less stringent level to protect healthy adults. State and federal programs to reduce emissions from school buses arise from concerns about potential health effects on children who ride those school buses. However, concerns about children do not necessitate an additional assessment as part of the permitting of the proposed plant. This is because the regulatory programs that are being implemented through this permit already address concerns about disproportionate impacts of emissions and poor air quality on children, wherever they are.

262. Additional modeling needs to be performed for the proposed plant to address the potential health hazard due to short-term SO_2 peaks, which are a potential threat to public health that is not adequately addressed by the current SO_2 NAAQS. In 1996, when USEPA reviewed the SO_2 NAAQS, it found that a five-minute SO_2 concentration of 0.6 ppm "should be regarded as significant from a public health standpoint" and "… repeated exposures to 5-minute peak SO_2 levels of 0.60 ppm and above could pose a risk of significant health effects for asthmatic individuals at elevated ventilation rates in some localized situations." Although USEPA decided not to set a new NAAQS for 5-minute exposures, its action was appealed and the Courts remanded the matter to the USEPA. Accordingly, the Illinois EPA cannot rely on USEPA's decision not to set a new NAAQS.

As the permit may not allow emissions at levels that would cause air pollution, an ambient SO_2 concentration of 0.6 ppm, 5-minute average, should be used as one of the criteria for determining whether the plant's SO_2 emissions would endanger public health. To do this, the permit should include the information necessary to evaluate whether the proposed plant would cause this criterion to be exceeded. This analysis should include a review of peak emissions and a modeling analysis to determine the likely occurrence of any such ambient peaks. Without this information, the Illinois EPA cannot determine whether more stringent SO_2 limits are required for the proposed plant.

USEPA has completed its further evaluation and concluded that peak concentrations of SO_2 are not a phenomenon for which the establishment of an air quality standard would be

appropriate. As an alternative, USEPA has proposed an intervention level program (ILP) to supplement the existing SO_2 air quality standards. The proposed ILP established a concern level for measured 5-minute average SO_2 concentrations. The ILP did not establish a modeling requirement for 5-minute average SO_2 concentrations. To implement this program, the Illinois EPA routinely reviews the ambient monitoring data that it collects to verify that concern and endangerment levels for SO_2 are not being exceeded. This review indicates SO_2 peaks, as addressed by this comment may be a concern for certain industrial facilities with relatively high rates of SO_2 emissions and low stacks. It would not be a concern for the proposed plant given its low SO_2 emission rate and tall stack.

263. Coal burning is a large source of the known carcinogen, dioxin. As part of the air quality analyses for the proposed plant, the Illinois EPA must conduct an assessment that includes background levels of dioxin in downwind areas and the exposure risk posed by the proposed plant's additional dioxin emissions. This must include not only inhalation, but also oral exposure pathways associated with food. This must also be done for cadmium, a chemical suspected to cause cancer.

USEPA has closely studied and continues to study dioxin emissions. It has not identified dioxin emissions from coal-fired power plants as posing a significant threat to public health or the environment that warrants the regulation of such emissions. As such, the small amounts of dioxin emitted from coal-fired power plants are distinguishable from those of other categories of sources that USEPA has identified as significantly contributing to the loading of dioxin in the environment, including waste incinerators, opening burning of waste ("burn barrels"), and low-temperature combustion of wood, i.e., wood stoves, fireplaces and campfires.

As a regulatory matter, dioxin is not subject to modeling requirements under the PSD program. Because dioxin is a hazardous air pollutant (HAP), it is addressed by Sections 112 and 129 of the Clean Air Act. As such, dioxin is generally to be addressed by USEPA with the adoption of technology-based MACT standards for HAP emissions, as needed to address the potential threats posed by emissions from both new and existing sources. Following implementation of such MACT controls, emissions are to be further addressed by USEPA in a comprehensive manner addressing both existing and new sources, to determine whether such controls adequately protect public health and the environment. If MACT is inadequate for this purpose, a process is set in motion for USEPA to adopt more stringent standards to protect public health. This is also the regulatory structure set up by the Clean Air Act for emissions of cadmium, as cadmium is also a HAP.

Air Quality Analysis/Modeling - Local Air Quality Impacts

264. The Illinois EPA should deny the permit, because the air quality analysis predicts that the proposed plant will contribute to exceedances of the National Ambient Air Quality Standards (NAAQS) for SO_2 and PM10 as well to exceedances of the PSD increment for PM10.

The modeled exceedances referred to in this comment are associated with existing sources in the modeling inventory. They are not a basis for permit denial because this is not a significant contribution by the proposed plant, i.e., the modeled contributions of the proposed plant are below the significant impact levels established by USEPA for various pollutants and averaging times. The Illinois EPA is investigating why the modeling showed these exceedances and tentatively believes that most are the result of erroneously high emission rates in the inventory. However, this review is still ongoing. The identification of potential exceedances associated with existing sources is an incidental benefit of the air quality analyses conducted by Prairie State.

265. Illinois EPA cannot issue a PSD permit to a source that will contribute to violations of the NAAQS or the air quality increments. The air quality analyses performed for the proposed plant predict that the plant would cause violations of the SO_2 and PM10 NAAQS.

Although the air quality analysis submitted by Prairie State shows modeled exceedances, these are due to *other* modeled sources. For all modeled impacts causing or contributing to exceedances, units at the proposed plant individually and in the aggregate did not contribute above the significant impact level for the relevant averaging period.

266. Prairie State's December 9, 2003 additional submittal indicates that the proposed plant total impact of SO_2 are 1998.9 ug/m3 for the 3-hour SO_2 NAAQS. This is more than 50% above the 3-hour SO_2 NAAQS of 1,300 ug/m3. Similarly, Prairie State modeled an impact of 501.73 ug/m3 for 24-hour averaging time, which is substantially above the 24-hour averaging time SO_2 NAAQS of 365 ug/m3.

For the 24-hour SO_2 NAAQS, Prairie State modeled 607.73 ug/m3 for the proposed plant and other modeled impacts. Adding the background value of 41.88, the highest value Prairie State found was actually 649.61 ug/m3 for the 24-hour SO_2 NAAQS rather 501.73 ug/m3 reported by Prairie State. Similarly, for the 3-hour SO_2 NAAQS compliance demonstration, the highest modeled value was 2,495.28 ug/m3. Adding the 143.97 background value yields a result of 2,639.25 ug/m3, which is significantly above the Prairie State reported value of 1,998.9 ug/m3.

The NAAQS for PM10 is 150 ug/m3 over a 24-hour period. The modeling submitted by Prairie State predicted that there will be a concentration of PM10 of 300 ug/m3.

These values cited in this comment are "hot spots" in the vicinity of certain existing sources and do not generally reflect the typical air quality levels that would be expected to occur with the proposed plant. For example, the SO_2 data is associated with three existing small coal-fired heating boilers at the Murray Development Center, located approximately 30 miles away from the site of the proposed plant. As such, the air quality impacts cited in this comment represent potential areas with high air quality levels that generally would be predicted independent of the proposed plant.

For emissions of SO_2 from the coal-fired boilers, Prairie State conducted culpability analyses to develop a short term (24-hour average) SO_2 emission limit for the coal-fired boilers that

would not be accompanied by a "significant" contribution from the proposed plant (in the aggregate) to any modeled NAAQS exceedance. This effort incorporated additional receptor assemblages, with finely resolved (100 meter receptor spacing) networks developed around the highest and second highest concentrations determined from a coarser grid. Prairie State modeled its coal-fired boilers using different emission scenarios (0.51 lbs/mmbtu, 0.44 lbs/mmbtu, 0.41 lbs/mmbtu, etc.) before settling upon a final emission rate. The modeled 24-hour impact of 607.73 ug/m^3 reflects the additional receptor resolution and the modeling results based upon 0.51 lbs/mmbtu, not the final 0.42 lbs/mmBtu limit that was settled upon.

The SO_2, 3-hour average, impacts cited in this comment have a similar basis. Additionally, Prairie State's maximum reported 24-hour average PM10 NAAQS impact should have been lower, to reflect the highest, 6th high concentration for the five years of modeled meteorological data. This is because of the statistical method used to determine compliance with this NAAQS, which extends beyond a single year.

267. Prairie State predicted ambient concentrations significantly above the 3-hour and 24-hour SO_2 NAAQS and 24-hour PM10 NAAQS. For Illinois EPA to issue a PSD permit when the applicant's analyses show a NAAQS violation would be contrary to the PSD program.

Whether a permit can be issued when an applicant's analyses show NAAQS violations depends upon the nature of the violation and the proposed source's contribution. Thus, it is not inherently "contrary to the PSD program" to issue a permit in such circumstances. The principle of *de minimis* air quality impact or "significant impacts levels" is an essential element of the PSD program and the performance of air quality analyses. The principle is addressed in the NSR Manual, which states the following with regard to a modeled violation of a NAAQS: "The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation. In such a case, the permitting agency, upon verification of the demonstration, may approve the permit" (page C. 52).

268. Prairie State attempts to rely on the significant contribution levels contained in 40 CFR 51.165(b)(1) to claim that it should be issued a PSD permit even though it modeled violations of the 3-hour and 24-hour SO_2 and 24-hour PM10 NAAQS. It claims that if its contribution to a NAAQS violation is below the significance level in 40 CFR 51.165(b)(1), it is not "culpable" for the violation and therefore should get its PSD permit. However, this is a legal error, because it is not consistent with the provisions of the Clean Air Act for the PSD Program, which prohibit a source from causing or contributing to a violation of a NAAQS or increment, not from significantly causing or contributing to a violation of a NAAQS or increment.

Prairie State also appears to rely on NSR Manual, page C.28, to justify issuance of a PSD permit after violations of NAAQS have been modeled. However, page C.28 provides significant levels for determining the significant impact area. The NAAQS violations modeled occurred in the significant impact area. Therefore, the significant impact levels on page C.28 are of no help to Prairie State. Further, it is worth noting that the NSR Manual, while persuasive on many issues, cannot override an issue on which Congress has directly spoken.

In addition, it is worth noting that Illinois EPA admits that the significant impact levels are arbitrary. They are not based on harm to people, wildlife or vegetation.

The legal analysis underlying this comment is flawed because it does not distinguish between two very different meanings applied to the term "significant." The exceedances predicted by the air quality analyses are not coincident with locations and time periods for which Prairie State emission units in the aggregate are predicted to contribute significantly, i.e., by more than a *de minimis* amount.

The *de minimis* or significant impact levels under the PSD Program do not reflect a determination of levels of impacts at which plants, animals or people may experience harmful impacts. Rather they reflect levels that have been established at small fractions of the applicable NAAQS to distinguish between impacts that are trivial and impacts that are worthy of further investigation and analysis. Most commonly, they reflect a threshold level of impact from a proposed source, by itself, that triggers a requirement for further detailed modeling analyses considering existing sources in the area and background levels of air quality.

269. Until such time as other sources have enforceable limits that are part of a State Implementation Plan that bring the levels of modeled impacts to below the NAAQS, a permit should be denied as long as the proposed plant is contributing to those NAAQS violations.

Another function of the de minimis or significant impact levels is to determine whether a proposed source should be considered to be causing or contributing to a violation. Prairie State's "culpability" analyses showed that the proposed plant would not have an impact above the significant impact levels for receptor/time combinations representing modeled NAAQS violations. Where only existing sources other than the proposed project are contributing above the significant impact level, the PSD program does not require that the applicant be denied a PSD permit until those contributing sources have enforceable limits to bring the levels of modeled impacts below the NAAQS.

270. Prairie State's SO_2 culpability analysis is flawed because Prairie State claims that with a limit of 0.42 lb/mmBtu, 24-hr SO_2, Prairie State will not significantly contribute to any modeled violations of the 24-hour SO_2 NAAQS. This is not accurate. Prairie State provided a list of what it claimed to be all of the time and receptor combinations in which Prairie State would have had a contribution of over 5.0 ug/m3 to a modeled 24-hour averaging time SO_2 NAAQS violation if Prairie State was emitting at 0.51 lbs/mmBtu. Prairie State then calculated what emission rate would bring these contributions down to 4.975 ug/m3, which would be below the claimed 5.0 ug/m3 "significant" level. However, Prairie State left out of its listing some of the proposed plant's highest contributions, and miscalculated some of the values. Based on this analysis, the proposed plant's 24 hour SO_2 limit could be no more than 0.37 lbs/mmBtu to remain below the significance level.

Illinois EPA or Prairie State may argue that for some of the time/receptor combinations the wrong emission rate (one that was too high) was used for the Murray Developmental Center (Murray Center) in Centralia. Actually, Prairie State's modeling used an emission rate for the Murray Center that was too low, rather than too high, so as to underestimate the SO_2 emissions. Also, the emission rates used are contrary to applicable regulations and reason. Presumably, the annual emission rates for Murray Center were based on the limit used to calculate permit fees. One cannot use a non-federally enforceable limit to determine emission rates to input into models for NAAQS compliance determinations. *See* 40 CFR Part 52, App. W, Table 9-2. Moreover, annual emissions cannot be not be used to determine compliance with short-term NAAQS.

The Illinois EPA concurs that for purposes of a short-term NAAQS compliance demonstration, the federally enforceable short-term allowable emission rate should be employed. The Illinois EPA based its determination on an allowable emission rate contained within its State-wide database, independent of any limit based upon any permit fee calculation. Although this limit was below Murray Center's short-term SO_2 limit, 6.8 lbs/mmBtu, 1-hour average, for emissions from its coal-fired boilers on a short-term basis, the permit limits SO_2 emissions below a level that would result in a modeled NAAQS violation due to any interaction between Murray and the proposed plant. In particular, the SO_2 emission rate needed to put rest any concerns about the impacts at Murray Center is 0.37 lb SO_2/mmBtu. This is above the "interim" limit for SO_2 emissions from the coal-fired boilers set in the permit, which will take effect 24 months after the initial startup of the proposed plant. As such, emissions from the proposed plant should not show any modeled NAAQS violation as a result of the interaction of the Murray Development Center and the proposed plant

In addition, under State rules, the Murray Center is subject to a short-term SO_2 limit, 6.8 lbs/mmBtu, 1-hour average, which restricts the emissions from its coal-fired boilers on a short-term basis. This is an enforceable limit that can appropriately be used in the short-term NAAQS modeling.

271. The culpability analysis should also include a fine grid analysis around any coarse grid receptors within 10% of NAAQS threshold, not just around coarse grid receptors that exceed the NAAQS, which is what Prairie State did. This is because a coarse grid receptor within 10% of the NAAQS threshold may exceed the NAAQS threshold when re-run with a fine grid. Therefore, Illinois EPA should require the applicant to run additional fine grid analyses around any course grid receptors that were within 10% of the NAAQS threshold in addition to the course grid receptors that exceeded the NAAQS threshold.

Prairie State's SO_2 culpability analysis is not "flawed" and, in fact, the analysis demonstrates that Prairie State's emissions will not cause or contribute to modeled violations of the 3-hour and 24-hour SO_2 NAAQS. The coarse grid and fine grid analyses, as performed, provide an ample basis for determining NAAQS compliance and culpability. The "event processor" file that was based upon 1990 meteorological data does include time and receptor combinations in which the aggregate contribution of Prairie State's units exceeds the highest contributions indicated by Prairie State in Table 2 of the December 9, 2003 submittal. However, these

contributions are for the highest concentrations at these receptors, and not the second highest concentrations. It is the second highest concentrations that are compared with the 24-hour SO_2 NAAQS and are the basis for determining whether Prairie State's emission units contribute significantly to a modeled exceedance.

The December 9, 2003 submittal was later superseded by a modeling analysis dated July 12, 2004 (Prairie State Generating Station Modeling Addendum #2), that included updated SO_2 culpability results, as a result of newly incorporated NAAQS inventory updates and a corrected anemometer height for the meteorological data sets. Corrected emission rates for sources at the Murray Center in both the December 9, 2003, and the July 12, 2004 submittals were based upon information obtained from the Illinois EPA's statewide pollutant inventory database. The values used were the highest allowable values.

272. Prairie State must model PM10 including accurate emission rates for all PM10 emission units. Certain units were not included in the modeling. In its PM10 modeling, Prairie State only modeled for two of the three diesel-fired fire water pumps. While the third fire water pump is included in the modeling files with the designation "EP26C," a closer look reveals that Prairie State set the emissions for EP26C to zero.

The entry for a fire water pump "EP26C" in the equipment inventory is for an electrically powered water pump, not a diesel-fired water pump. Consequently, there are no emissions associated with this piece of equipment.

273. The PM10 modeling does not include an emergency diesel generator. Illinois EPA stated that there was no need to model an emergency diesel generator because one was not proposed for this plant. The Project Summary simply states that the proposed plant will have various diesel engines. It would seem highly unlikely that a coal-fired power plant would be built without an emergency source of power in the event of power failures. It is important to note that Thoroughbred Generating Station, Prairie State's identical facility in Kentucky, was proposed with an emergency diesel generator. However, Prairie State's consultants noted that the emergency diesel generator may cause a PM10 violation.

Most importantly, we are concerned because Prairie State's permit currently allows the construction of diesel fueled engines. (Condition 1.5.) It is also of concern because Prairie State's modeling consultant indicated in the Thoroughbred proceeding that an option is to file for a permit that one has no intention of complying with and then negotiating less restrictive permit limits after obtaining the initial permit. *See* Ex. 35 at Point 4. If this is true, Prairie State may obtain its permit without modeling for the impacts from an emergency diesel fired generator and then construct an emergency diesel fired generator after obtaining a minor permit modification or not even obtaining a minor permit modification. This is a concern because the emergency diesel fired generator could cause or contribute to violations of the PM10 NAAQS and increment when it is routinely tested or operated for internal plant power needs.

Therefore, in order to be enforceable as a practical matter, the permit needs to allow the two diesel fired water pumps with a PM emission rate of no higher than 0.7 g/s PM. The permit also needs to explicitly state that Prairie State cannot construct any other diesel fired engines, including an emergency diesel fired generator, without submitting a complete new PM10 increment and NAAQS analysis including the routine operations of the emergency diesel fired generator. To the extent that Illinois EPA refuses to include such provisions, we reserve our right to submit supplemental modeling that includes an emergency diesel fired generator. This concern about the impacts from an emergency diesel generator applies not only for PM10 but also NOx and possibly SO_2.

An emergency diesel generator was not included in the modeling analysis because Prairie State did not propose one in its permit application. Because Prairie State is only permitted for two engines, adding an additional unit would require a new or revised permit, which would have to appropriately address that development. Incidentally, the potential impacts from a hypothetical emergency diesel fired generator would not be expected to materially affect the results of the air quality analysis for PM10 and SO_2, but could for NOx.

274. The PM_{10} modeling must include emissions from other sources, including the mine, Ameren Energy's Pinckneyville power plant, Dynegy's Baldwin coal handling and other equipment.

The Prairie State Mine is part of the proposed source and has been included in the modeling. Local sources of particulate emissions, including Ameren Energy's Pinckneyville peaker plant and Dynegy's coal-fired Baldwin power plant (coal handling and other emissions), have been included in the PM10 modeling.

275. The application explains that the majority of the mine's operations will be underground. The air underground must be vented. However, the mine vent was not included in the PM modeling but it should have been.

Mine vents, which reflect ventilation air, were excluded consistent with common modeling practice that does not include comfort ventilation systems in air quality analyses. The impacts from such units would be adequately accounted for in the background values used with the air quality analyses. In addition, emissions would be both negligible and difficult to quantify. As noted in NSR Manual, emissions "to the extent they are quantifiable" are to be considered in the air quality impact analyses.

276. Prairie State's PM NAAQS modeling needs to include Ameren Energy's Pinckneyville peaker plant, which is within the PM significant impact area plus 50 kilometers of the proposed plant.

The follow-up air quality analysis dated July 12, 2004 (<u>Prairie State Generating Station Modeling Addendum #2</u>) superseded the December 9, 2003 submittal and incorporated inventory updates such as the inclusion of Ameren Energy's Pinckneyville peaker power plant.

277. Prairie State did not include in its PM NAAQS modeling PM emissions from Baldwin's coal handling equipment, coal crushing operations and fly ash equipment. Prairie State needs to redo the PM NAAQS modeling to include these additional sources. When calculating the

emission rate, Prairie State must also take into account that Baldwin's permit claims to allow Baldwin to continue to operate in violation of the PM limits for the coal handling equipment, coal crushing operations and fly ash equipment. In light of this provision, Prairie State must include emission estimates for these units that are higher than the permit limits. The uncontrolled potential to emit seems to be the appropriate value for the purposes of this modeling exercise.

An assessment of the emissions from the Baldwin power plant was conducted in developing the modeling inventories. As mentioned previously, the July 12, 2004 modeling submittal included emission inventory updates. Modeled sources from the Baldwin power plant did include emissions from coal handling equipment, coal crushing operations, roadways, the Baldwin Thermal Treatment Facility, fly ash silos and other units. Modeled emission rates are based upon operating permit data and limits and in accord with current modeling guidance. Coal handling operations at the Baldwin power plant will be subject to stringent requirements in the Title V permit.

278 The emission rates assigned to fugitive units of PM in the modeling are not justified because of a lack of practically enforceability. The emission rates that were used in the PM modeling for certain "fugitive" emission units at the proposed plant are unjustifiably low. The PM emission rates for these units were based on assumptions about the efficiency of the associated control measures. *See* Ex. 41. Bill Powers, P.E., an engineer with decades of experience in working on coal-fired power plants, reviewed the control efficiencies on which the modeled emission rates were based. Mr. Powers' report is attached as Exhibit 40. Mr. Powers concluded for the reasons set forth in his report that the efficiencies used to calculate the PM emission rates could not be justified based on the application or conditions of the draft permit. The "fugitive" units at the plant that are affected by this issue include the coal piles and certain coal processing and transfer equipment as well as certain other material handling operations. *See* e.g. Ex. 19 Thus, the Illinois EPA must either place conditions in the permit that require the control efficiencies underlying the modeling to actually be achieved through specification of the control equipment and associated monitoring, record keeping, and reporting, or require that the PM modeling be redone using reasonable worst case efficiencies considering the application and draft permit conditions. A reasonable worst case control efficiency for the active coal piles would be 40% rather than 90%, so that the appropriate emission rate to model would be six times higher than the rate that was used. Similarly, for the conveyor transfer building, the appropriate rate would be 45 times higher than the rate that was used.

Prairie State must achieve the levels of fugitive dust control reflected in the emission rates used in the air quality analyses. The issued permit contains additional provisions in response to this comment to more directly address this, including explicit statements of the required level of control for fugitive dust, e.g., 90 percent control for storage piles. Mr. Powers' comments in his letter to Robert Ukeiley (May 18, 2004) address the perceived lack of detailed control technique information, rather than the achievability of stated control efficiencies.

279. The ISC model is not appropriate for the Class II increment modeling. The significant impact area for SO_2 was determined to be 50 kilometers (km) based on the fact that this is

the limit of the ISCST3 model. *See generally* Ex. 10. In such a situation, it is appropriate to use a different model, with a longer range for the SO_2 modeling. *See* NSR Workshop Manual at C.32. In fact, Prairie State's own expert, Joe Scire, has testified that it would be appropriate to use CALPUFF in such a situation. *Sierra Club v. KY Environmental and Public Protection Cabinet and Thoroughbred Generating Company*, File No. DAQ-26003-037 and DAQ-26048-037, Transcript of 11/21/03.

The ISC3 model was appropriate for this Class II modeling application, even with an SO_2 significant impact area of 50 kilometers. The NSR Manual recognizes the possibility of significant impact areas extending out to this distance, and requires that "nearby sources" (those causing a significant concentration gradient) that are "anywhere within the impact area or an annular area extending 50 kilometers beyond the impact area" be included in the NAAQS and PSD increment modeling analyses. Moreover, the NSR Manual goes on to say the following:

> **The Modeling Guideline indicates that the useful distance for guideline models is 50 kilometers. Occasionally, however, when applying the above source identification criteria, existing stationary sources located in the annular area beyond the impact area may be more than 50 kilometers from portions of the impact area. When this occurs, such sources' modeled impacts throughout the entire impact area should be calculated. That is, special steps should not be taken to cut off modeled impacts of existing sources at receptors within the applicant's impact area merely because the receptors are located beyond 50 kilometers from such sources. Modeled impacts beyond 50 kilometers should be considered as conservative estimates in that they tend to overestimate the true source impacts. (page C.32)**

Thus, an over-prediction of ambient concentrations at these large distances would be expected. The use of any alternative model is at the discretion of the regulatory agency.

280. Increment modeling must be conducted for all areas inside the significant impact area. It appears that Prairie State only conducted increment consumption modeling in those areas where the minor source baseline date has been set for a particular pollutant. This is not an acceptable approach. Since the Major Source Baseline Date has long since past, the applicant must conduct increment modeling for all areas inside the Significant Impact Area and its buffer. If the minor source baseline date has not been established for a particular county for a particular pollutant, then the applicant need only include major sources, which of course includes the applicant's facility, in its increment modeling.

PSD increment as described in the NSR Manual is identified as "the maximum allowable *increase* in concentration that is allowed to occur above a baseline concentration for a pollutant" (page C.3). Increment consumption is evaluated for PM, SO_2 and NO_2 from a fixed, initial date—Major Source Baseline Date—for construction at existing major stationary sources, and from a subsequent Minor Source Baseline Date set by the receipt of the first completed PSD application by the permit reviewing authority and subsequent to a second fixed date—Trigger Date. Increment consumption following the Minor Source Baseline Date is for all sources, not just new construction at existing major stationary sources. Prairie State

conducted increment consumption modeling only in those areas (counties) where the minor source baseline date has been set for a particular pollutant. This approach accords with Illinois EPA's interpretation of how the USEPA modeling guidance is to be applied.

281. Prairie State must determine through modeling if the minor source baseline date has been established. Illinois EPA claims that Prairie State established the minor source baseline date for PM10 and SO_2 for Washington County. However, a review of Illinois EPA's list of when minor source baseline dates were established reveals that Illinois EPA only considers a minor source baseline date to be established when a major source locates in the county. *See* Ex. 20 and 21(no minor source baseline dates established by sources outside of the counties). However, minor source baseline dates are established when a major source submits a complete permit application for a facility in the county in question or in any other county where the facility will have a 1 ug/m3 impact on an annual average. *See* 40 CFR 52.21(b)(15)(i).

    For example, Illinois EPA needs to determine whether the Mississippi Lime in Randolph County or the proposed project from PANDA Corp in Jefferson County established the minor source baseline date for PM10 or SO_2 in Washington County prior to the Prairie State application. Once the actual minor source baseline date for Washington County is determined, then Prairie State needs to re-do its Class II increment modeling for PM10 and SO_2.

The Prairie State application did establish the minor source baseline date for PM10 and SO_2 in Washington County. No other major source from within or outside the county is known to have contributed impacts that exceeded the significant impact threshold for PM10 and SO_2. The final revision (February 4, 1993) for the <u>PSD Air Quality Review for Four New Rotary Lime Kilns at the Prairie du Rocher Facility Mississippi Lime Company Prairie du Rocher, Illinois</u> provided a maximum significant impact area radius of 35.33 km (SO_2). The corresponding significant impact area did not extend into Washington County. The Panda Energy application (received June 1, 2001) for a proposed natural gas fired power plant was not a complete submittal, and the application was withdrawn December 12, 2002.

282. The modeling was missing several other recent sources that must be included in the PM10 and SO_2 increment and NAAQS modeling. The PM10 NAAQS modeling only includes 20 sources in addition to Prairie State. However, the PM10 increment modeling includes 27 sources. There is no reason why the all of the sources in the increment modeling should not have also been included in the NAAQS modeling. Therefore, Prairie State should have to redo the NAAQS modeling and add in any sources from the increment modeling that it did not include.

As noted earlier, Prairie State submitted modeling results dated July 12, 2004, that incorporated inventory updates. Sources inadvertently omitted from prior analyses were included in the modeling runs, along with other supplemental inventory changes determined by the Illinois EPA as appropriate. The revised modeling results addressed the NAAQS as well as Class II increment consumption. All increment consuming sources appeared in the NAAQS modeling inventories.

283. The Baldwin Expansion project must be included in the modeling for the proposed plant. The Baldwin expansion applied for its PSD permit on April 5, 2002. Prairie State's application was submitted October 11, 2002. It is USEPA's policy that sources are to be included in the emissions inventory based on the date of submission of the complete permit application. Therefore, Prairie State must include the Baldwin Expansion in its SO_2 and PM NAAQS and Increment modeling. Illinois EPA claims that Prairie States' application was submitted on October 19, 2001. However, Illinois EPA determined that the 2001 application was not complete for PSD purposes. Thus, the complete application date for PSD purposes was submitted October 11, 2002, which is after the date Illinois EPA received the Baldwin Expansion permit application.

Emission sources from the proposed Baldwin Power Plant expansion were not included because the completed Prairie State permit application was received prior to receipt of the completed Baldwin expansion application.

The proposed Baldwin Power Plant expansion project's air quality analysis includes Prairie State and EnviroPower. Conceivably, any future PSD application must include Prairie State, EnviroPower and the proposed Baldwin expansion.

284. In addition, the EnviroPower project in Benton, Franklin County, must be included in the SO_2 and PM10 NAAQS and Increment modeling for Prairie State. The EnviroPower application was received on August 16, 2000, even before Prairie State's first incomplete application. Thus, it must be included in Prairie State's modeling. Finally, the Franklin Energy Coal Project, also in Benton, must be included as Illinois EPA received its application on June 7, 2002, which is before the revised Prairie State application was received on October12, 2002.

The EnviroPower project in Franklin County was evaluated as part of the inventory updates for SO_2 and PM10 NAAQS and increment modeling for the air quality analysis for the proposed plant. The only emission units that remained in the inventory after screening for distance and emission rate were the larger SO_2 emission units, notably the main boilers. The Franklin Energy Coal Project was not included in the air quality analysis because the Illinois EPA has only received an application for the project and Prairie State acquired standing over that application when Franklin Energy failed to supplement its submittal with necessary information.

285. Prairie State needs to model emissions from startups and shutdowns. *See* 40 CFR Part 52, App. W, Section 9.1.2. Because the short-term emission limits do not apply during startup and shutdown it would be impermissible and arbitrary to use inapplicable emission limits in modeling. Moreover, even if one assumed that this proposed plant will be a baseload facility, which is an assumption that could only be rationally made if there was support for it in the record, a baseload facility can and will definitely startup more than once a year. Thus, the uncontrolled potential to emit should be used as the emission rate for modeling startups. However, the uncontrolled potential to emit would result in a violation of the 3-hour SO_2 NAAQS and Increment. If 98% control results in a three-hour impact of 123.7 ug/m3, then

uncontrolled emissions would result in an impact of over 6,000 ug/m3, which is well above the NAAQS and the Increment. In addition, inclusion of startup emissions when the SCR will not be operating would surely result in an annual impact of greater than the 1 ug/m3 "significant" level for NOx. Thus, Illinois EPA either needs to add emission limits during startup and shutdown that are protective of the NAAQS and increments or deny the permit.

Prairie State submitted modeling results to address elevated emissions that can occur during periods of startup and shutdown. The Illinois EPA considers the 1-hour average carbon monoxide impacts and the 3-hour average SO_2 impacts to be the relevant evaluations during startup/shutdown. Modeled concentrations for the impacts of Prairie State alone were well below the respective NAAQS for these pollutants and averaging times. Boiler startup will utilize natural gas firing and then transition to coal firing as temperatures are ramped up to operating levels. Modeling the boilers at the "uncontrolled potential to emit" emission rate for coal firing would be inappropriate, since the boilers are initially fired with natural gas and SO_2 control equipment is brought on line with increasing feed of coal during ramp up.

Though not specifically modeled, increased NOx emissions during startup would not be expected to result in an annual impact that would exceed the NO_2 annual standard, nor the significance level (1 ug/m3) for this pollutant. In the absence of NO/NO_2 speciation data, USEPA modeling guidance provides a default value of 75% for that portion of the NOx emitted which is believed to be NO_2. This dramatically lowers the likelihood that the NO_2 NAAQS or the significance level would be exceeded, even during that period when the SCR is not operating.

286. Independent modeling confirms that Prairie State will cause a violation of both the 24-hour PM10 NAAQS and PM10 Class II Increment. The source inputs were obtained from data files on the applicant's modeling CD. The modeler modeled for the Prairie State sources, background NAAQS sources and background PSD sources. The modeling parameters for all Prairie State and other sources were included.

Modeling was performed for the coarse, 1-km grid (extending 50 km from Prairie State), and for a denser, near grid. The near grid included a 100 meter grid extending 2 km from Prairie State, along with the fence line grid. All receptor locations and elevations were taken directly from modeling files contained on the modeling CD provided by Illinois EPA. Although there are quite a few modeled violations occurring over the 1-km grid, there are no instances when the proposed plant has a modeled impact greater than the significant impact levels used by Prairie State. However, when looking at the near grid receptors, the same cannot be said. There are instances, both for the annual and 24-hour averaging periods, where Prairie State has contribution to a modeled violation above the significant impact levels. In fact, often these high values are primarily due to Prairie State. All told, 46 time-receptor combinations were found in violation of the 24-hour PM10 NAAQS and the 24-hour PM increment. Fifteen time-receptor combinations were found in violation of the annual PM10 NAAQS and annual PM10 Increment. Therefore, Illinois EPA cannot issue a permit for the plant.

The conclusions reached through independent modeling performed or available to the commenter appear to be based upon data files that lacked the most current information or that contained errors. As mentioned previously, Prairie State supplied updated PM10 NAAQS and Class II increment modeling results (submittal dated July 12, 2004) that reflect inventory corrections and updates and implementation of a corrected anemometer height. The contributions of Prairie State emissions to modeled exceedances of the PM10 NAAQS and the 24-hour PM10 increment were below the significant impact levels. There were no time-receptor combinations for which Prairie State impacts exceeded the significant impact levels.

Air Quality Analysis/Modeling - Air Quality Analysis For Ozone

287. The modeling protocol must include preconstruction monitoring for ozone. The proposed plant has a potential to emit (PTE) of over 100 tons per year of volatile organic compounds (VOCs). Therefore, Prairie State is required to gather preconstruction ozone levels. *See* 40 CFR 52.21(i)(5)(i), Footnote 1.

Since Prairie State has the potential to emit over 100 tons per year of VOCs, pre-construction ozone monitoring is required unless the Illinois EPA determines that existing ozone monitoring adequately characterizes ambient concentrations for the area encompassing the proposed plant. The Illinois EPA has determined that the existing monitoring adequately characterizes ambient ozone concentrations.

288. There is an existing ozone monitoring station in Randolph County that Prairie State claims is representative of its site. In 2002, this station monitored a violation of the 8-hour ozone standard. Therefore, Prairie State must rely on this data.

The Illinois EPA appears to have waived the requirement for pre-construction ozone monitoring. This is arbitrary. Even if the failure to conduct pre-construction monitoring were legal, the permit must require post-construction ozone monitoring.

The Illinois EPA has determined that the existing ozone monitor (Houston site) in Randolph County is representative of ozone concentrations in proximity to the proposed Prairie State plant and has waived the requirement for pre-construction monitoring. Requiring post-construction monitoring is at the discretion of the permitting authority, and the Illinois EPA has not identified a need for post-construction ozone monitoring to supplement the Houston site monitoring.

289. The ozone modeling for Prairie State was inadequate both because the modeling did not include Dynegy's Baldwin plant and the modeling for the one-hour ozone NAAQS was inadequate. Although Illinois EPA required Prairie State to conduct ozone modeling, Prairie State refused to include the Dynegy plant in its ozone modeling. There is no basis for this exclusion. NAAQS modeling must include all existing and proposed sources.

Cognizant of the resource requirements for an applicant to perform photochemical grid-based modeling, the Illinois EPA conducted ozone modeling to assess the impact of the proposed

Prairie State plant, the proposed Baldwin Power Plant expansion, and other proposed or recently permitted (as of 2002) power plants in the 1-hour average ozone attainment demonstration for the Metro-East/St. Louis area. For Illinois, this includes the Illinois counties of Madison, Monroe and St. Clair. Electrical generating units within the base emission inventory included the large number of "peakers" permitted and operating within the past seven years. Actual emission rates for these "peakers" were determined from operational data that were more likely to reflect summertime conditions.

290. Ozone modeling must be based on the short-term emission limit for Prairie State. Illinois EPA evaluated modeled to determine if Prairie State will cause or contribute to a violation of the old, 1-hour ozone NAAQS. However, this modeling was flawed in that Illinois EPA used the wrong emission rate for Prairie State. Illinois EPA used an emission rate of 0.08 lbs/mmBtu and 14.47 tons per day. However, 0.08 lbs/mmBtu is not the permit limit that should be used for ozone modeling based on a 1-hour averaging time. Rather, as Illinois EPA and USEPA have insisted, short-term emission limits should be used when modeling for short-term impacts. In this case, the permit contains a 24-hour averaging time limit of 893 lbs/hr. This is the equivalent of 21.432 tons per day. Therefore, the 1-hour ozone modeling should be redone using 21.432 tons per day for Prairie State, which is based on the short term NOx limit for Prairie State.

The Illinois EPA determined that performing the modeling using BACT or maximum permitted emission limits was an acceptable, conservative approach and consistent with application of the model in developing the 1-hour ozone attainment demonstration for the Metro-East/St.Louis area. In the prior ozone attainment demonstration, average actual emissions of ozone precursors, rather than allowable emissions, had been used.

291. The ozone modeling should consider all locations. Conducting the "Relative Reduction Test" for just one monitor location, as Illinois EPA did, is arbitrary. The fact that this monitoring location currently has the highest predicted design value does not mean that that monitor location will have the highest design value after all of the new electrical generating units are operating. Thus, the Relative Reduction Test should be conducted for all of the ozone monitoring locations.

Although Illinois EPA only published Relative Reduction Factor (RRF) results for the highest design value monitor (West Alton) in the Metro-East/St. Louis Area, it did calculate the impacts on the design values for the remaining monitors in the area. Even with the impacts of adding the electrical generating units, the adjusted design values according to the relative reduction factor "test" for these monitors were well below the 1-hour ozone standard. The West Alton monitor remained the highest design value of all the monitors.

292. Illinois EPA's report also states: "In locations where the maximum ozone increases due to the new electrical generating units are greater than one part per billion (ppb), the background ozone concentrations predicted by the model are **generally** well below the level of the NAAQS." Illinois EPA does not explain what it means by "generally." This is a concern because the new electrical generating units increased ozone levels by as much as 30 ppb. Illinois EPA should provide all of the locations where the maximum ozone increases due to

the new electrical generating units are greater than 1 ppb, and a list of the background ozone concentrations predicted by the model for all of those locations.

As depicted in the threshold plots in Figures 12-19 of the Illinois EPA's report (*Assessing the Impact of the St. Louis Ozone Attainment Demonstration from Proposed Electrical Generating Units in Illinois*, September 25, 2003), ozone increases as a result of new electrical generating units "generally" occurred in grid cells where ozone was less than 100 parts per billion (ppb). The one exception to this occurred during the July 12, 1995 episode day when the ozone level in the ozone "plume" extending north northeast from St. Louis was greater than 100 ppb but less than 124 ppb. The greatest effect of power plant emissions predicted by the modeling was to increase the ozone concentration in very small areas of the plume by 1 to 3 ppb, one-hour average. However, given the origin and orientation of the plume, this effect cannot be attributed to the emissions of the proposed plant.

293. The Project Summary misleadingly states that ozone models are not applicable to a single source with small amounts of emissions. The fact that Illinois EPA required and conducted ozone modeling for Prairie State shows why this statement is misleading. Therefore, Illinois EPA should hold a new public comment period in which it admits that ozone modeling can and was done for this project and provide the public with the results of the new ozone modeling done in accordance with the procedures discussed in this comment.

It is generally recognized that photochemical grid models are not best applied in trying to ascertain the impacts of a *single* source. The modeling performed by Illinois EPA actually evaluated the impacts of numerous, discrete power plant projects (Prairie State, Dynegy Baldwin Expansion, Illinois Energy Group (Franklin Energy Coal),EnviroPower, Southern Illinois Power Cooperative, and others). Photochemical grid modeling is not conducted on a single source basis, but if it were, efforts would be made to assure it was done in a technically sound manner.

294. Prairie State must model to determine if it will cause or contribute to a violation of the 8-hour ozone NAAQS. Effective June 15, 2004, Washington County was designated attainment/unclassifiable for the 8-hour ozone NAAQS. As Prairie State did not have a permit by that date, it must demonstrative that it will not cause or contribute to a violation of the 8-hour ozone NAAQS. 40 CFR 52.21(k)(1). There is no "grandfathering" under this provision. It does not matter that Prairie State submitted its application before the 8-hour designation became effective. When modeling for the 8-hour ozone NAAQS, my comments in Section 6(A) would equally apply.

Since the proposed plant has the potential to emit over 100 tons per year of VOCs, an assessment of the potential ozone air quality impacts through an accepted screening methodology (Scheffe, 1988) or alternatively, through photochemical modeling, was required by the Illinois EPA. USEPA Region V has indicated that a 1-hour ozone assessment should still be used as a surrogate for the 8-hour ozone standard for PSD air quality reviews. Accordingly, as already discussed, the Illinois EPA conducted photochemical modeling to address the impact of the proposed plant and other power plant projects as reported in *Assessing the Impact of the St. Louis Ozone Attainment Demonstration from Proposed Electrical*

Generating Units in Illinois. **This modeling demonstrated that these power plant projects did not endanger attainment of the 1-hour ozone standard, which is still in effect as it was not immediately superseded when USEPA adopted the 8-hour ozone standard.**

While this modeling focused on the 1-hour ozone standard, consistent with guidance from USEPA, it also provides relevant insight on the impact of new power plant projects on the 8-hour ozone standard. This is because the modeling also identified grid cells during each day of the selected ozone episodes in which the base concentration of ozone was above 80 ppb in any hour. For this purpose, this modeling is very conservative, overstating the identified changes in ozone levels, as they reflect 1-hour impacts, rather than 8-hour average impacts. For such grid cells, the modeling then identified the change in ozone levels associated with the power plant projects. This analysis shows that the proposed plant would not have a significant impact on ozone levels that were in excess of 80 ppb, one-hour average. Predicted impacts that can be specifically attributed to the proposed plant, based on their orientation and the orientation of the St. Louis air mass, are not routine and only occur when the wind direction is such that the Dynegy Baldwin plant and the proposed plant are in line. The geographic extent of the impacts is small, with the maximum predicted increase in ozone levels between 5 and 7 ppb, on a one hour average. Moreover, these particular impacts predicted by this modeling are also overstated as the NOx emissions that were modeled for these two plants are now about 40% higher than the greatest emissions that might be expected. (BACT for NOx for the boilers at the proposed plant is set at 0.07 lb/million Btu, rather than 0.08 lb/million Btu; the emissions of the proposed new Boilers 4 and 5 at Baldwin were based on 0.12 lb/mmBtu and the existing Baldwin power plant was based on 0.15 lb/million Btu, rather than the requirement of the pending Consent Decree, which would limit emissions to 0.10 lb/million Btu).

295. As an alternative argument, it should be noted that the Prairie State mine and power plant should be treated as a single source. I understand that the mine extends into St. Clair County, which is nonattainment. 40 CFR 81.314. Therefore, Prairie State did not have to do 8-hour ozone NAAQS modeling because Prairie State is actually in an ozone nonattainment area. Therefore, until the Illinois EPA confirms that no portion of the proposed plant is located in (or under) St. Clair County, Prairie State must obtain a nonattainment NSR permit for ozone.

Although the mine facility and the power plant will be treated as a single source, and the underground portions of the mine *may* extend into St. Clair County, the source cannot be treated as being located in a nonattainment area. The emission units and fugitive emission points for the proposed plant are located in an attainment area, and are not located in a nonattainment area.

296. The Project Summary concludes that the proposed plant will not cause a violation of the 1-hour ozone standard in the Metro-East/St. Louis maintenance area and that the effect under the upcoming 8-hour ozone standard can be dealt with later. As soon as the 8-hour standard goes into effect, the Metro-East /St. Louis will again be in nonattainment, so that study should be done now.

As indicated above, the PSD regulations require an evaluation of the potential air quality impacts of the proposed facility. Also, on June 15, 2004, U.S. EPA officially promulgated an 8-hour ozone standard and designated the Metro-East/St. Louis area (including the Illinois counties of Jersey, Madison, Monroe, and St. Clair) as a moderate nonattainment area. As described in the rule, states with areas designated as "moderate nonattainment" must develop and adopt State Implementation Plans (SIPs) by June 2007. These SIPs describe what measures the states will take to show monitored attainment by 2010. In response to the June 2004 designation, the states of Missouri and Illinois are currently conducting research, including modeling, that addresses the impact of emission sources (including impacts from Prairie State) on 8-hour ozone levels in the Metro-East/St. Louis area.

Air Quality Analysis/Modeling - Analyses for Secondary Impacts – Soils, Vegetation, Etc.

297. Prairie State's analysis of the impacts of the proposed plant on soils and vegetation, including commercial crops, showed impacts above the levels of concern.

Secondary National Ambient Air Quality Standards (PM10, SO_2, NO_2, ozone, and lead) are public welfare-based standards and are considered to be protective of plants, animals and soils. Modeling results for the proposed plant do not exceed the secondary NAAQS. In Table 6.7.3-1 of the revised Prairie State permit application, the applicant provides a comparison of modeled SO_2 and NOx impacts against sensitive vegetation impact thresholds---"minimum reported levels at which visible damage or growth effects to vegetation may occur." These thresholds appear in Table 3.1 ("*Screening Concentrations for Exposure to Ambient Air Concentrations*") of the USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (EPA 450/2-81-078). The modeled impacts do not exceed these threshold criteria. A revised table provided as part of a supplemental "additional impacts analysis" (received December 10, 2003) compared modeled SO_2 and NOx impacts against sensitive vegetation impact thresholds, and showed that modeled impacts were well below the threshold criteria. Calculated deposited soil concentrations for metals and hydrogen fluoride (Table 7.3-1 of the additional impacts analysis), based upon modeled maximum annual average ambient concentrations for the proposed plant's emissions, were all below the screening levels provided in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*.

298. The proposed plant's emissions will increase ozone, fine particle and other pollution levels downwind of the plant. As a part of Prairie State's soil and vegetation analysis, it must consider the impacts of each of the pollutants on soil and vegetation, including any identified rare species and other species with particular ecological or economic value.

Prairie State's "Additional Impacts Analysis" included a qualitative assessment of ozone impacts on vegetation and a quantitative assessment of the impacts of particulate metals, in addition to the impacts described above for SO_2 and NO_2. In this regard, the PSD regulations

only require an analysis of the impacts of a proposed plant on vegetation that has a significant commercial or recreational value.

In addition, separate from its evaluation conducted for purposes of the PSD program, Prairie State conducted additional assessments that assisted the Illinois EPA and USEPA in conducting consultation on endangered and threatened species under applicable state and federal law. Prairie State also performed a Screening Level Ecological Risk Assessment to evaluate impacts of selected compounds of potential ecological concern (arsenic, chromium, lead, mercury, selenium, and dioxins/furans) on threatened and endangered species and their habitats, and for Illinois Natural Area Inventory sites. The potential for long-term adverse effects on habitats or for chronic health effects on species was determined to be unlikely.

299. Prairie State's additional impacts analysis addressing ozone impacts to soils and vegetation is inadequate. The analysis relies on outdated scientific studies, all before the 1997 revision of the ozone NAAQS, to claim that because Prairie State will not cause a violation of the 1-hour ozone NAAQS, it will not cause harm to vegetation. Contrary to Prairie State's claim, just last month USEPA stated:

> Each year, ground-level ozone is also responsible for crop yield losses. Ozone also causes noticeable foliar damage in many crops, trees, and ornamental plants (*i.e.*, grass, flowers, shrubs, and trees) and causes reduced growth in plants. Studies indicate that current ambient levels of ozone are responsible for damage to forests and ecosystems (including habitat for native animal species). 69 *FR* 21,604 (April 21, 2004).

In fact, USEPA's 1980 guidance document that Prairie State relied upon states that sensitive plants are susceptible to ozone damage at 0.06 ppm over an 8-hour period, which is lower than the 8-hour NAAQS of .08 ppm. More recently, Illinois EPA concluded that "[a]dverse effects on sensitive vegetation have been observed from exposure to photochemical oxidant concentrations of about 100 ug/m3 (0.05 ppm) for 4 hours." *2002 Illinois Annual Air Quality Report*.

Prairie State goes on to claim that it is "difficult to determine the contribution the proposed plant will have on local or regional ambient ozone levels. Since the Illinois EPA has done an analysis of the proposed plant's impact on ozone so it must not be too difficult. However that analysis only looked at whether the plant will contribute or cause violations of the 1-hour NAAQS, i.e., 0.125 ppm. Prairie State needs to use the modeling already done to determine if it will contribute to ozone levels that adversely effects vegetation, that is 0.06 ppm, 8-hour average and 0.05 ppm, 4-hour average.Prairie State's also claims that VOCs are the pollutant of concern, but the Illinois EPA has stated that NOx is the pollutant of concern. Prairie State's claim that NOx contributions to ozone are regional and have been addressed by the NOx SIP Call, is wrong on both counts. The Southern Appalachian Mountain Initiative (SAMI) found that the greatest reductions in ozone levels are achieved by local NOx reductions. As to the NOx SIP Call, it was solely designed to help achieve compliance with the 1-hour ozone NAAQS, not the level at which vegetation is harmed. Therefore, Illinois EPA should reduce Prairie State's NOx emission limit until the modeling shows no impacts above the level at which vegetation may be adversely affected, that is 0.06 ppm 8-hour average, and 0.05 ppm 4-hour average.

The ozone air quality standards are both "primary" and "secondary" standards. As such, these standards are regarded as protective of both public welfare (plants, animals, and soils) and of human health. It is not appropriate to look to an alternative standard for sensitive vegetation to generally protect vegetation from any adverse impacts, as suggested by this comment. The modeling analysis conducted by the Illinois EPA to assess the impacts of Prairie State and other proposed or recently permitted power plants on the Metro-East/St. Louis 1-hour ozone attainment demonstration showed clearly that the 1-hour ozone standard would still be met and that the established attainment plan would not be jeopardized. As already discussed, while not focused on the 8-hour ozone standard, this modeling also contains information that indicates that the proposed plant would not threaten vegetation compared to the 8-hour ozone standard.

300. Prairie State's Additional Impacts Analysis is not adequate as related to selenium (Section 7) because it used the wrong emission rate and failed to add in background concentrations, as required by USEPA guidance. This analysis must be redone and then re-public noticed for a new comment period.

In a December 9, 2003 Memorandum from Steve Bjorklun and Carl Weilert of the engineering firm, Burns & McDonnell (B&M), to Kevin Finto, a lawyer with Hunton and Williams, B&M explains that selenium removal, because it is a volatile metal like mercury, is difficult. B&M explains that the collection of selenium would be within the range of 60% to 80% but B&M anticipates that Prairie State will perform at the high end of this range. However, Prairie State lists the control efficiency for selenium as 99.90%. Prairie State offers no reason why it rejected the opinion of B & M, and picked the 99.90% control efficiency for selenium to get a controlled emission rate of 0.0025 lbs/hour rather than the emission rate at 80% removal efficiency of 0.1017264 lbs/hour.

Table 7.3-2 then provides estimated ambient impacts from Prairie State, alone, based on the emission estimates. Table 7.3-2 lists selenium as having an emission rate of 0.25432. This is a typographical error. Apparently Prairie State meant to write 0.0025432 rather than 0.25432 lbs/hr. Table 7.3-2 states that selenium's emission rate in grams per second is 0.00020. It appears to have been incorrectly copied from the grams per second emission rate for beryllium. Using the correct emission rate for selenium of 0.1017264 lbs/hr yields an emission rate of 0.0128 g/s. The 0.0128 g/s yields an annual concentration of 0.0045952 ug/m3 of selenium on an annual average.

Prairies State failed to add this concentration to background concentration. *See* Ex. 117 USEPA document EPA-450-2-81-078 "*A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*." at 27 - 28, especially Section 5.1.2. Because the USEPA guidance document does not provide background data for Washington County or surrounding counties, the appropriate step is to do a sensitivity analysis using a value from another county. Even if the 99.000 ug/m3 minimum geometric mean for Tarrant County is excluded as being inconsistent with the other values, a conservative assumption is to use the next highest minimum geometric mean value reported at 0.2000 ug/m3 for Taylor County. This yields a value of 0.2045952 ug/m3.

Taking the 0.2045952 ug/m3 and applying that to the formula results in 58.6506239 ppmv selenium as a deposited concentration. This substantially exceeds the screening level in the USEPA Guidance Document. Prairie State either needs to do additional analysis by determining local selenium background concentrations or do a complete analysis of Prairie State' impacts to soils.

The Additional Impacts Analysis (December 9, 2003 submittal) provided by Prairie State for selenium emissions is not flawed. In the December 9, 2003 memorandum from Steve Bjorklun and Carl Weilert (Burns & McDonnell) to Kevin Finto (Hunton & Williams), the authors describe selenium as a volatile (gas phase) trace metal that is difficult to control, yet USEPA's <u>Compilation of Air Pollution Emission Factors, Volume I</u> (AP-42) discussion on Bituminous and Sub-bituminous Coal Combustion (Section 1.1) indicates that trace metal partitioning in the gas phase for combustor emissions in some cases includes selenium (page 1.1-5). With this uncertainty in selenium partitioning, there can be a wide range of control efficiency values that may be appropriate for selenium emissions from the boilers.

The reported selenium emission rates (in units of both pounds per hour and grams per second) in Table 7.3-2 of the December 9, 2003 supplemental information submittal are not consistent with the tabulated selenium data appearing in Attachment 3 ("Coal Quality HAP Calculations") of that same document. The former are believed to be typographical errors. Despite this inconsistency, the reviewer is provided with the equation for calculating controlled emission rates (see Attachment 3) and the methodology for determining calculated impacts (Table 7.3-2), so as to have the means to determine what the correct estimated value should be. The predicted maximum annual average ambient concentration for selenium is presented in Table 7.3-1 ("Impacts on Soils and Vegetation"), and when it is used to calculate other values appearing in that table, it results in an incorrectly calculated deposited soil concentration and potential concentration in plant tissue. These errors result in underestimates, but the values are still well below the screening threshold values recommended in Table 3.4 of USEPA's screening document (EPA 450/2-81-078). Ambient air selenium concentrations reported by the Illinois State Water Survey from their Bondville, Illinois atmospheric research station (BEARS) may be representative of background values. Based upon seventeen PM2.5 samples collected with dichotomous samplers over the period from February 1999 through September 1999, the average mass of selenium was 0.001 micrograms per cubic meter. Adding this ambient background value and a recommended endogenous soil concentration value of 0.5 ppmw (EPA 450/2-81-078, Table 3-5) to the calculation of deposited soil concentration and potential plant tissue concentration would still result in values well below the published soil and tissue screening levels (see December 9, 2003 supplemental submittal, Table 7.3-1).

Since these earlier calculations, Prairie State has changed its calculation of selenium emissions from the coal boilers to reflect 80% control efficiency. Assuming a 40-year life for the plant, rather than a 30-year life, results in a calculated deposited soil concentration of 0.077 ppmv and, similarly, a potential plant tissue concentration of 0.077 ppmv. In combination with

estimated background selenium ambient air concentrations and the recommended endogenous selenium soil concentration, the calculated deposited soil concentration and potential plant tissue concentration would still be significantly below screening concentration threshold levels.

301. Prairie State's Additional Impacts Analysis is flawed as related to cadmium. The emission rate for cadmium is listed as 0.00136 lbs/hr. This converts to 0.00017 g/s, rather than the 0.00015 listed in the analysis. This equals 0.000061517209271 ug/m3 on an annual average. This then needs to be added to background value. Converting this to a soils concentration based on the appropriate formula yields 0.01763493332435328924600002245 ppmv of cadmium in the soil. Using the concentration ratio of 10.700 yields 0.18869 ppmv.

As with selenium, the Additional Impacts Analysis (December 19, 2003 submittal) provided by Prairie State for cadmium is adequate. Despite likely typographical errors (Table 7.3-2 of the December 9, 2003 information submittal), calculated deposited soil concentration and potential plant tissue concentration values are well below the screening soil concentration and plant tissue concentration threshold levels (Table 3.4, EPA 450/2-81-078). Filter analysis data (TSP samples) for cadmium as reported in the Illinois Annual Air Quality Report 2002 shows that the Macoupin County monitor, which we believe is more representative of rural conditions than any of the other monitors for which cadmium was measured, produced an arithmetic mean concentration of 0.000 micrograms per cubic meter. Modeled and background concentrations, in combination with the recommended endogenous soil concentration (0.06 ppmw), produce values that are also well below the screening soil concentration and plant tissue concentration threshold levels.

302. Prairie State should have considered pollution from the train spur, as trains are a significant source of air pollution. *See* e.g. http://www.epa.gov/otaq/ap42.htm. One of the growth related impacts from the proposed plant will be the addition of a rail line to serve the plant. Therefore, the soils and vegetation analysis needs to include the emissions from the rail line that will be built to serve the plant. *See* e.g. NSR Manual at D.4.

While the proposed plant will have a rail spur to receive and transfer bulk materials, the amount of actual traffic on the spur will be small, typically a train or two per day. Accordingly, the emissions and impacts of rail traffic will not be significant. This would be the case even during interruptions of the mine-mouth coal supply, when two trains per day would likely be sufficient to supply coal to the plant. In this regard, train traffic may be considered a significant contributor to air quality in urban areas, but this is a consequence of the volume of train traffic in a small area. Federal programs are also underway on a national basis to reduce emissions from diesel locomotives.

302a. The growth analysis submitted by Prairie State, for the proposed plant, which indicated that little or no growth would occur, is contradicted by other information, including information in promotional material or press releases concerning the proposed plant.

The material on growth submitted by Prairie State is the relevant analysis of growth impacts and reflects a reasonable assessment of the effects of the proposed plant. As the proposed

plant is located on the border of the St. Louis area, with its large, established work force, it is appropriate to expect that the plant will generally be built and operated by individuals already living in the area. These individuals will likely continue to live throughout the area, particularly as they like their current home, community and local schools. They also will continue to patronize the same businesses. While they may commute to a different job or job site, they will no longer commute to their former job or job site, so that a significant change in transportation related emissions should not be expected. With regard to the effect of the plant on emissions from mobile sources, it is also relevant that the NSR Manual specifically excludes emissions from mobile sources and construction activity from consideration in the growth analysis. "Excluded from consideration as associated sources are mobile sources and temporary sources." NSR Manual, page D.3.

Thus, it is unclear that there will be any "growth" associated with the proposed plant that would lead to additional air quality impacts. Certainly, the effect of the plant on growth is not amenable to a quantitative analysis, as might be the case if the work force in an area was inadequate to support a proposed source or the proposed source would necessitate the development of separate sources to support the proposed source. In this case, the mine necessary to support the power plant is already part of the proposed source. There are also other power plants and large industrial facilities in the St. Louis area. With respect to other documents concerning the proposed plant, it is important to clearly distinguish between growth and economic benefits. While the proposed plant can be readily shown to contribute to the local economy, through salaries and taxes that it pays, that does not mean that it will lead to significant new residential, commercial and industrial "growth" that it will be accompanied by an increase in emissions.

303. The screening level for SO_2 used in Prairie State's soil and vegetation analysis is not adequate. This analysis used 786 ug/m3 as the short-term screening value for SO_2 adverse impacts to vegetation. However, this level is an order of magnitude too high. Studies have show that vegetation can suffer adverse impacts from exposure to SO_2 at 79 ug/m3. *See* Ex. 42 at 116 (0.03 ppm x 64 / 24.45 x 1000 = 79 ug/m3). Therefore, Prairie State should have to redo its soils and vegetation analysis using an SO_2 screen value of no higher than 79 ug/m3 over a 1-hour average.

As recommended, Prairie State has compared SO_2 modeling results for the proposed plant against minimum screening levels for visible vegetation damage or vegetation growth effects in sensitive vegetation as provided in Table 3.1 of "*A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*" (EPA 450/2-81-078). The proposed plant's maximum reported 3-hour average impact (98.39 ug/m3), in combination with an appropriate 3-hour average background concentration (143.97 ug/m3), are well below the threshold screening level (786 ug/m3). Other information that may be available in the published literature addressing the effects of SO_2 on vegetation has not been found by the Illinois EPA, nor fully demonstrated by the commenter, as an appropriate substitute for the USEPA provided information used in this analysis.

Class I Modeling/Impacts on AQRVs at Mingo

304. The Class I modeling for Mingo cannot screen out NOx and PM based on proposed significant impact levels. Prairie State's submittal explains that it did not do a cumulative Class I increment analysis for PM10 and NO_2 because initial modeling for Prairie State, alone, showed that Prairie State's impacts would be below the **proposed** Class I significant impact level. However, it is contrary to law to rely on a proposed regulatory standard. In fact, the D.C. Circuit has held that "there are some areas, such as national parks, where any deterioration would probably be viewed as significant." *Sierra Club v. EPA,* 540 F.2d 1114, 1121 (D.C. 1976). The D.C. Circuit went on to explain that "Enforcement of the limitation on incremental pollution is accomplished partly through preconstruction review of 19 categories of stationary sources considered to be significant sources of pollution. Permission to construct or to modify significantly one of the listed stationary sources is conditioned on a showing that the source's emissions, together with all other increases or decreases in emissions in the area since January 1, 1975, will not violate the air quality increments applicable to any area." *Id*. at 1123 (footnote omitted). Therefore, Prairie State must conduct a cumulative impact analysis for the NO_2 and PM Class I increments.

The Illinois EPA considers it appropriate to use the proposed Class I significant impact levels for SO_2, PM10 and NO_2 as thresholds for determining the need for a cumulative impact increment consumption analysis. Though only proposed, the use of such thresholds is consistent with USEPA policy (Memorandum from John Calcagni to Thomas J. Maslany, September 10, 1991). This memorandum notes that "The Office of Air Quality Planning and Standards recently initiated action that will lead to rulemaking to address the general need for Class I significant impact levels. The action is part of EPA's efforts to implement the new PSD/new source review provisions in the 1990 Clean Air Act Amendments". The author also states that "I see no reason . . . why the concept of significant impact should not also be applied to Class I increments provided the significant impact levels are determined in a reasonable manner".

305. The US Fish and Wildlife Service (USFWS) has expressed concern that Prairie State used an incomplete inventory of PSD increment consuming sources in Prairie State's Class I analysis. We incorporate by reference all inadequacies pointed out by the U.S. Department of Interior and any of its sub-agencies including the National Park Services' Air Resources Division.

The USFWS commented that it is concerned that the PSD Class I increments in the Mingo Wilderness Area have not been accurately analyzed for the proposed Prairie State project, and that an incomplete inventory of PSD increment consuming sources from the State of Missouri (and maybe other nearby states) may have underestimated the total cumulative Class I increment consumption in the Mingo Wilderness Area and also may have underestimated Class II increment consumption. USFWS specifically commented that the recently-permitted Plum Point Generating Station in Arkansas had not been included in the inventory. However, Prairie State subsequently included this source in the inventory. Missouri emission inventory deficiencies, if in fact they exist, have not been identified by either USEPA Region VII or the USFWS. In the absence of such information, the Illinois

EPA has no reason to question the continuing validity of these inventories; the modeling inventories must be considered to be complete. (*See, Appalachian Power Company v. EPA,* 135 F.3d 791, 802 (D.C. Cir. 1998), "The agency's choice of a model will be sustained if it bears a 'rational relationship' to the characteristics of the data to which it is applied").

Illinois EPA responded to concerns raised by USFWS regarding the Class I SO_2 increment inventory in a letter to the Deputy Assistant Secretary for Fish and Wildlife and Parks (January 13, 2005). The Illinois EPA relied upon its own statewide air pollution database, as well as inventory information received from Missouri's Department of Natural Resources, surrounding states, and the USFWS in facilitating the development of the Class I modeling analyses. The Class I increment consumption modeling performed by Prairie State reflects the inventory information made available to it, including corrected inventory omissions identified by the USFWS. Further emission inventory deficiencies, if in fact they exist, have not been identified by either USEPA Region VII or the USFWS. In the absence of such information, it is unreasonable to not accept the Class I SO_2 increment modeling inventory.

306. Prairie State will have an adverse impact on Class I air quality related values, including visibility, at Mingo. On May 14, 2004 the Federal Land Manager (FLM) for the Mingo Wilderness Area determined that Prairie State will cause adverse impacts on Air Quality Related Values (AQRV) at Mingo. We incorporate by reference these concerns. The FLM made a finding that there would be adverse impacts on AQRV and he found that Prairie State had not demonstrated that the proposed plant will not cause or contribute to violations of the Class 1 increments for SO_2 and PM. Therefore, pursuant to Clean Air Act section 165(d)(2)(C)(i), a "permit shall not be issued."

The preliminary adverse impact determination by the Federal Land Manager (letter dated May 14, 2004) for the Mingo Wilderness Area is not a determination with which the Illinois EPA concurs. The Illinois EPA provided explanatory remarks in regard to its non-concurrence to the FLM (letter to Paul Hoffman, Deputy Assistant Secretary, Fish and Wildlife and Parks, United States Department of the Interior, dated January 13, 2005).

Prairie State provided modeling analyses that show the visibility extinction for the three-year period modeled was negligible. While the Illinois EPA considered the FLAG guidance, the Illinois EPA recognized that the FLAG guidance must be interpreted to include the effects of weather phenomena (rain, snow, fog, drizzle, etc.) on natural background light extinction and visitor use of the Class I area. *See* Letter from Craig Mason, Assistant Secretary for Fish and Wildlife and Parks, to Jan Sensibaugh, Director, Montana Department of Environmental Quality, dated January 10, 2003 ("In its 'Recommended Prescription' for analyzing impacts from sources greater than 50 km from 'Class I' areas, the FLAG report specifically articulates that visibility impairment or extinction is to be '. . . compared against natural conditions . . .' It is our interpretation that 'natural conditions' include significant meteorological events such as fog, precipitation, or naturally occurring haze."). As noted in the FLAG guidance, an adverse impact on visibility is defined in federal visibility protection regulations (40 CFR 51.300, *et seq*., Section 52.27) as "visibility impairment, which interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Federal class I area. This determination must be made on a case-by-case basis taking

into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with: (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. (*Id.* Section 51.301 (a)).”

Prairie State visibility modeling scenarios adjusted to include the effects of weather events on natural background light extinction resulted in only five days exceeding the 5% extinction threshold and one day exceeding the 10% extinction threshold over the three years modeled. When hours of visitation are considered, this reduces to only four days in three years when either of the thresholds is exceeded. Moreover, analyses performed by Dr. Ivar Tombach (*Natural Visibility Conditions at the Mingo Wilderness Area* (July 6, 2003) and *Human Perception of Visibility Impairment at the Mingo National Wildlife Refuge and Wilderness Area* (July 6, 2003)) support a conclusion that there would not be an adverse visibility impact.

The Illinois EPA has discussed with USFWS their concerns and comments on whether the adjustments made to the FLAG model are appropriate under the circumstances presented by this permitting transaction. The Illinois EPA, however, does not believe that it is appropriate for USFWS to have taken the position that no adjustments to the FLAG model may be considered because to do so would impact “consistency and fairness to all potential PSD applicants”, as not all PSD projects are similarly situated. Existing air quality conditions, pending regulations, weather, wilderness area or park usage and hours may vary significantly from area to area, and models already very conservative in nature should ease those more conservative assumptions where appropriate.

The Illinois EPA’s reading of the FLM letter, as a whole, indicates that the finding is preliminary and based on the materials received as of the date of the letter, May 14, 2004. In fact, the FLM states that it is making its finding under Clean Air Act section 165(d)(2)(c)(ii), and also states that it hopes to continue to work with the Illinois EPA to resolve the issues related to visibility. A number of additional meetings and conference calls were held after the date of this letter in an effort to resolve the visibility issue, and enhancements are included in the issued permit that were made to ameliorate any potential adverse impacts on the Mingo Wilderness Area from the proposed coal-fired power plant.

These measures were not considered as part of the USFWS’ original evaluation. These measures include: setting the BACT limit for NOx from 0.08 rather than at to 0.07 lbs/mmBtu; reducing the daily SO_2 limit by 20% within 24 months of start-up of the boilers; setting a BACT limit for SO_2 in terms of control efficiency, i.e., 98% reduction in SO_2 emissions on a rolling 12-month basis; and subjecting the plant to a lower annual limitation on SO_2 emissionsuntil 2011. Prairie State is also required to purchase 25% more SO_2 allowances than are required to comply with the existing Acid Rain program in proportion to actual SO_2 emissions of the proposed plant until a program such as Clean Air Interstate Rule (CAIR) takes effect to address emissions of SO_2 and NO_x from coal-fired power plants as a group.

In addition, USFWS has not considered other related developments that affect emissions of Illinois’ coal-fired power plants, i.e., the development of a Consent Decree to specifically

address emissions of Dynegy's plants, including the Baldwin plant, and the USEPA's actual adoption of CAIR.

307. Even if one accepts Prairie State's efforts to justify and excuse the visibility impacts that Prairie State's own modeling showed, Prairie State predicted that there would be at least one day over a 10% change in visibility. FLMs have traditionally objected to a permit application that shows a 10% or greater change in visibility. Similarly, Prairie State's own modeling showed the nitrogen and sulfur deposition flux exceeded the analysis threshold. Therefore, regardless of Illinois EPA consideration of the issues below, Illinois EPA should not issue this permit until emissions are reduced to the point where there are no adverse impacts on visibility at Mingo by Prairie State alone.

Modeled Prairie State sulfur and nitrogen deposition fluxes, for certain years, do exceed the sulfate and nitrate deposition analysis thresholds identified in the FLAG guidance. However, for the region encompassing and including the Mingo Wilderness Area, the buffering capacity of surface soils, surface sediment and underlying bedrock (limestone) is expected to effectively neutralize acidic inputs of sulfur and nitrogen. Potential aquatic ecosystem changes (e.g., eutrophication) from the fertilizing effects of increased nitrogen deposition would not be expected to be significant. An analysis conducted by James R. Kramer (*Aquatic Assessment of Mingo Wilderness Area (MWA)*, August 1, 2003) of the depositional impacts of Prairie State in the Mingo Wilderness Area concludes "there would be a non-detectable change in precipitation chemistry and in the surface water acid-base chemistry with the additional deposition contribution from Prairie State Generating Station." The Illinois EPA found Dr. Kramer's analysis persuasive regarding the site-specific factors at Mingo.

FLAG recognizes that depositional critical loads should be reviewed based on new information. *FLAG* at p. 131. Moreover, the significant regional reductions in SO_2 and NOx emissions that have occurred and will continue to occur were not considered as part of the USFWS' original evaluation.

308. In regards to the need to do a cumulative analysis, the reductions at Baldwin are not enforceable through a permit limit, a State Implementation Plan or SIP requirement. Therefore, the reductions are not relevant to a PSD modeling exercise. Similarly, the claim that some of the SO_2 credits under the acid rain program that Prairie State will obtain will come from other sources near Mingo is baseless speculation, especially considering the many years that Prairie State is planned to operate. Likewise the Clean Air Interstate Rule (CAIR) is just proposed. It can take at least a decade between a proposed rule and its implementation, if the rule ever does get implemented, due to industry challenges. Therefore, consideration of this rule is not appropriate.

For short-term averaging period PSD increment analysis, USEPA modeling guidance contained in the NSR Manual allows for the use of the maximum actual emissions rate "during the previous two years of operation" (see page C.49). Thus, the reductions in SO_2 emissions from Baldwin and other power plants are relevant to the PSD increment analysis, and were incorporated into the Class I modeling submitted by Prairie State.

The USFWS stated in its comments that it believed the impacts of the proposed plant could be offset by air pollution reductions from current existing sources near Prairie State, and that any proposed reductions should be evaluated to show that the mitigation of impacts in the Mingo Wilderness Area would be measurable in Mingo and should be verified as a federally enforceable permit condition for participating sources.

While the Illinois EPA does not believe that offsets are necessary for this permitting transaction, included in the project summary (sent to USFWS with the draft permit), the Illinois EPA noted that emission reductions from the Ameren Grand Tower facility were available. USFWS has not explained why these reductions are not acceptable as a legal matter, as the reductions occurred after the baseline date for the Mingo Wilderness Area set under the PSD program, they are contained in a federally enforceable permit, that facility is closer to Mingo than the proposed plant, and these reductions would be creditable under the federal Clean Air Act. Moreover, it is the geographic relationship of Mingo to offsetting sources that is of relevance to this analysis. Also, as previously discussed, Prairie State has agreed to purchase additional SO_2 allowances under the Acid Rain Program from the period of start-up of the plant until CAIR or a similar rule takes effect, so as to assure that the operation of the proposed plant is accompanied by an overall decrease in emissions of SO_2 from power plants.

The Illinois EPA also noted that Dynegy's Baldwin plant had reduced SO_2 emissions by over 200,000 tons per year since 2002. The FLM did not accept these reductions as mitigation of potential impacts of the proposed plant.

However, Illinois EPA continues to maintain that the Ameren offsets are valid, creditable offsets. In addition, the emission reductions from the Baldwin plant cannot reasonably be ignored. This is particularly true as a Consent Decree was filed in March 2005 with the United States District Court for the Southern District of Illinois, which when entered by the court, would make these emission reductions at the Baldwin plant enforceable. As to the Acid Rain Program, as with all emission trading programs, one does not necessarily know from which source the allowances will be obtained. However, the accepted premise, and demonstrated reality, of the Acid Rain Program is that the benefits of the program will be seen in the entire region. Monitoring has been shown to be the case. Moreover, the impacts on air quality, and visibility, at Mingo that already exist are in large part regional, and therefore, improvements within the region will result in improvements at Mingo.

309. Prairie State's Class I analysis must follow FLAG. In preparing its visibility analysis, Prairie State used the IWAQM methodology rather than the FLAG methodology. However, FLAG, and not IWAQM is applicable to the Prairie State project because Illinois EPA received the Prairie State Class I modeling protocol on March 18, 2003, and Illinois EPA received the complete application on October 11, 2002, which is after the FLAG applicability date of April 1, 2001. Therefore, Prairie State must submit a new Class I modeling protocol and conduct a new Class I analysis using FLAG.

The Prairie State Class I modeling analysis implemented the FLAG methodology.

310. Prairie State's visibility analysis uses the wrong baseline to determine the percentage change. Prairie State originally used a visibility baseline that includes impacts from non-natural sources and thus does not reflect natural conditions. Visibility analysis must use natural conditions as the baseline. *See* 40 CFR 51.301 (definition of visibility impairment incorporated into 40 CFR 52.27(b)).

Prairie State Class I visibility assessment for the Mingo Wilderness Area used the visibility baseline data and procedure contained within the FLAG guidance.

311. Prairie State's application misstates the standard for notification of the FLM when there is a project within 100 km of a Class I area. Prairie State's permit application incorrectly states that the FLAG guidance provides that the permitting agency must give notice to a FLM when it receives a PSD permit application that is located within 100 kilometers (km) of a Class I area or will have a significant impact on a Class I area. FLAG actually provides that the permitting agency should notify the FLM when it receives a PSD permit application for a "'very large sources with **the potential to affect** Class I areas proposing to locate at distances greater than 100 km." FLAG at 9. Prairie State, at 11,868 tons of SO_2 and 5,400 tons of NOx, is obviously a very large PSD source when compared to the PSD threshold of 100 tons of any pollutant. In addition, Prairie State has a potential to affect the Mingo Wilderness Area because it consumes almost all of its Class I increment. Therefore, Illinois EPA was required to give notice of the Prairie State permit application pursuant to the regulatory deadline.

The Illinois EPA gave notice of the Prairie State application to the Federal Land Manager in mid-April 2002, and has adhered to known procedural requirements pursuant to that notification.

Modeling and Impacts on Air Quality Related Values at Class I Areas

312. As stated in its Project Summary, the Illinois EPA anticipates improvements in visibility in the Mingo Wilderness Area in southeastern Missouri because southern Illinois power plants have reduced their emissions. The Illinois EPA should also consider any other projects that would worsen visibility, especially the new Holcim cement plant that has recently been permitted for construction in Ste. Genevieve County, Missouri.

There have been large reductions in the actual SO_2 and NOx emissions of Illinois' existing power plants, notably Ameren's Grand Tower plant and Dynegy's Baldwin plant. The amounts of these reductions far exceed the permitted emissions of both the proposed plant and the new Holcim cement plant, so as to compensate for the emissions of these new sources as they affect the Mingo Area.

In addition, the effect of the proposed plant on the Mingo Area is further minimized as it is subject to the federal Acid Rain Program and the NOx Trading Program, which comprehensively address emissions from all but the smallest coal-fired power plants. These programs require operators of affected power plants to hold and retire SO_2 and NOx

allowances each year to cover their actual annual emissions of SO_2 and actual seasonal emissions of NOx. They set an overall budget on emissions from affected plants as only a fixed number of allowances is allocated to plants each year. As Prairie State must hold and retire allowances for its emissions of SO_2 and NOx, other power plants will have to emit less, either as other plants operate less, as allowances are now allocated to Prairie State, or other plants better control their emissions and have surplus allowances to sell to Prairie State.

Finally, other recent actions will act to further reduce the impact of power plants, including the proposed plant, on the Mingo Wilderness Area. The Consent Decree for Dynegy's Baldwin power plant will require a specific reduction in local emissions. CAIR will require a reduction in overall emissions from power plants, and will certainly provide local reductions due to the number of power plants in the region around the Mingo Wilderness Area.

313. Prairie State should model for impacts on Mammoth Cave National Park. The Calpuff model is capable of modeling up to 300 kilometer and even beyond that distance. Thus, because the proposed plant is well within the 300 kilometer range of the Calpuff model, impacts on Mammoth Cave should be modeled. This is especially important because it is very likely that the short term SO_2 increments for Mammoth Cave have been fully consumed.

There is no regulatory requirement for assessing impacts at Mammoth Cave National Park, which is located approximately 315 kilometers away from the proposed plant. While Prairie State evaluated impacts to the Mingo Wilderness Area, it is located only about 140 kilometers from the proposed plant. The comments from the USFWS on Prairie State's protocol for the Class I modeling did not include any objections to the protocol as it addressed impacts to the Mingo Wilderness Area, and no other Class I area.

In addition, the ability of the CALPUFF model to address Mammoth Cave is not clearly established. When USEPA incorporated CALPUFF into its *Guideline on Air Quality Models*, it stated "CALPUFF is appropriate for long range transport (source-receptor distances of 50 to several hundred kilometers) of emissions from point, volume, area, and line sources." [68 FR 18475, April 15, 2003]. It also noted "Commenters generally agreed that the CALPUFF modeling system has adequate accuracy for use in the 50-200 km range, with some studies showing that acceptable results can be achieved at least out to 200 to 300 km. Since the 7th Modeling Conference, enhancements were made to CALPUFF. . . These enhancements likely will extend the system's ability to treat transport and dispersion beyond 300 km." (p. 18441). In addition, the USEPA recommends caution in the use of CALPUFF for long-range transport distances in excess of 300 km. Refer to Exhibit A of the Settlement Agreement between the Utility Air Regulatory Group and USEPA (No. 03-1168) in the U.S. Court of Appeals for the District of Columbia Circuit.

314. The Illinois EPA did not give adequate notice of why it was rejecting the Federal Land Manager's Adverse Impact Finding on Air Quality Related Values. The public notice simply mentions that the USFWS submitted information that is further addressed in the Project Summary. The USFWS found that even using the 30 day SO_2 emission rate, the proposed plant would cause 36 days over 5% change in the extinction threshold for visibility

and 12 days over the 10%. Consistent with Federal Land Managers Air guidance, USFWS explained that this would cause an adverse impact. However, the Project Summary only mentions one day over 10% and four days over 5%, without accounting for the discrepancy in findings.

In addition, USFWS explained that deposition of sulfates and nitrates are crucial because of their ecological effects at Mingo. USFWS found that the proposed plant's deposition impacts are almost ten times the deposition threshold for sulfates and twice that for nitrates. USFWS states that atmospheric deposition on land and water is a concern at Mingo. However, there is no analysis of impacts to wildlife and vegetation in the Mingo Wilderness area from mercury. As wildlife and vegetation are Air Quality Related Values, and as mercury levels in fish are a concern, Illinois EPA should require an analysis of mercury impacts including bio-concentration and bio-magnification.

The Illinois EPA appropriately provided its basis for rejecting USFWS' adverse impact determination. Pursuant to 40 CFR 52.21(p)(3), a public notice must include either an explanation or notice indicating where the explanation may be found. The public notice for the draft permit indicated where the Illinois EPA had addressed USFWS' concerns and explained its finding of no adverse visibility impact, which satisfied applicable requirements.

As limited by the permit, the emissions of the proposed plant will comply with the applicable PSD requirements. "Visibility impairment" is that "which interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Federal Class I area." This determination is made on a case-by-case basis considering a number of factors and how these factors correlate with "(1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility." 40 CFR 52.21(b)(29). Modeling that is consistent with this definition shows that Prairie State will not adversely affect visibility at Mingo. Research demonstrates that a 20% change in visual air quality is needed for a change to be discernable. At no time does Prairie State's modeling for three years of weather data show that the emissions of the proposed plant would create any perceptible change in visibility. In terms of acid deposition, the Illinois EPA concluded that Mingo is in an area that is highly buffered by calcareous bedrock, so that any additional acidic inputs from the proposed plant would not have any appreciable effects on the ecosystems at Mingo.

In addition, these comments do not accurately reflect the potential concerns for air quality related values at Mingo expressed by the USFWS. For example, the USFWS did not identify ecological effects at Mingo from acid deposition. The USFWS expressed general concerns about acid deposition given that Mingo is located in a region, which stretches east to the Appalachian Mountains, in which levels of acid deposition in the United States are generally the highest.

Finally, applicable rules do not provide for an analysis of mercury impacts to wildlife and vegetation. PSD provides for a Class I analysis. However, mercury is a HAP and HAPS are exempt from PSD, under Section 112(b)(6) of the Clean Air Act. Nevertheless, the Illinois EPA requested an assessment of mercury in the impact analysis and the performance of a

Screening Level Ecological Risk Assessment. These show that the proposed plant's emissions will be well below the screening values. In addition, Prairie State will be subject to applicable federal regulations for control of mercury emissions. The proposed permit requires the plant to be equipped with modern emission controls and to emit only a fraction of the mercury emitted by existing plants, appropriately expressed per megawatt of electricity produced.

315. On May 14, 2004, after the start of the public comment period, the USFWS determined that the proposed plant would have an adverse impact on the wilderness area at the Mingo Wilderness Area. This was based on its further evaluation that found that the plant would cause deterioration in visibility in the Mingo Area to exceed the level noticeable to people for 36 days per year.

The USFWS' further comments do not demonstrate that an adverse impact on air quality related values at the Mingo Wilderness Area would actually occur as a result of the proposed plant. The USFWS comments reflect a methodology for the performance of visibility impact evaluations that, while based on guidance prepared by the Federal Land Managers Air Impact Work Group, does not accurately address the actual impact of the proposed plant on air quality related values in the Mingo Area. The USWFS' comments also do not address the regulatory requirements for a showing of adverse air quality impact. Nor do they address additional enhancements in the permit issued for the proposed plant that are intended to reduce the potential for such impacts. Most notably, Prairie State will retire 25 percent more SO_2 allowances than required to comply with the Acid Rain program, in proportion to its actual emissions, until (1) implementation of additional cap and trade federal regulations or legislation, such as the Clean Air Interstate Rule (CAIR), or (2) other new federal or state rule limiting SO_2 emissions from power plants is adopted. This commitment by Prairie State goes significantly beyond the requirements of the federal Acid rain program, which already requires that Prairie State obtain and retire SO_2 allowances on a one-for-one basis and acts to prevent any net increase in national SO_2 emissions from power plants as a result of the operation of the proposed plant. Finally, recent actions such as the Consent Decree for Dynegy's Baldwin power plant and CAIR will reduce the impact of power plants, including the proposed plant on Mingo.

USEPA's Consultation under the Endangered Species Act (ESA) and National Environmental Policy Act (NEPA)

316. USEPA has failed to comply with its obligations under the federal Endangered Species Act prior to close of the public comment period. At the close of the comment period, USEPA has not even commenced consultation. Consultation should be completed prior to the close of the comment period in order for the public to be able to review the results and consider them when preparing comments on the draft permit for the proposed plant.

The ESA consultation process must consider all endangered and threatened species that may be affected by emissions from the proposed plant, including potential effects of mercury emissions on aquatic ecosystems. The consultation process must extend to species that exist or have critical habitat within the Greater St. Louis Area, given the status of current air quality for ozone and PM2.5. This consultation must consider background pollution levels, as well as the cumulative impacts of the proposed Holcim cement plant and the proposed Baldwin expansion.

Prairie State's initial biological assessment is defective in numerous ways. Foremost is its arbitrary decision to only assess ecological impacts within 27 kilometers of the proposed plant. In light of the USFWS's determination that Prairie State's proposal will adversely affect the air quality values at the Mingo Wilderness Area – located approximately 140 kilometers away – the ESA consultation must, at a minimum, consider endangered species and threatened species that exist or have critical habitat within 140km of the proposed site.

The USEPA has completed its obligations for consultation under the federal Endangered Species Act, as confirmed by correspondence exchanged between the USEPA and the USFWS. This occurred following informal consultation on the potential impacts of the proposed plant on endangered and threatened species. The various circumstances broadly pointed to by this comment, which are not further supported by any technical discussion, are not relevant to the consultation process. Consultation is conducted on a project specific basis. A decision to focus scrutiny on the area surrounding the plant is not arbitrary as the maximum air quality impacts from a plant would occur in such area. The potential for impacts on visibility at the Mingo Wilderness Area does not demonstrate the existence of biological impacts in such area, particularly given the conservative methodology by which such impacts were predicted. Perhaps, most significantly, the nonattainment status of the greater St. Louis area indicates that there will be improvements in the air quality in that area, which will be accompanied by improvements in air quality in areas that are downwind of St. Louis, like the site of the proposed plant. Finally, there are no provisions under the Clean Air Act, the Endangered Species Act, or the PSD regulations that provide for the public to participate in the consultation process under the Endangered Species Act or to formally comment on the conclusions that result from the consultation process.

The Illinois EPA has also fulfilled its obligations under the Illinois Endangered Species Protection Act and underlying regulations. The statute generally provides that any construction authorized by a state agency that (1) will result in a change to the existing environmental conditions and/or may have a cumulative, direct or indirect adverse impact on a listed species or its essential habitat, or (2) that otherwise jeopardize the survival of that species and/or may have a cumulative, direct or indirect adverse impact on a Natural Area, shall be evaluated through a formal consultation process involving the Illinois DNR. The Illinois EPA properly consulted with the Illinois DNR. The process was initiated after the Illinois EPA filed a formal Agency Action Report. Upon request, the Illinois EPA subsequently submitted a number of documents comprising the Detailed Action Report to the Illinois DNR. Following a review of the Detailed Action Report, the Illinois DNR issued its biological opinion on November 1, 2004. The Illinois DNR found that "the adverse impacts resulting from the proposed action are not likely to jeopardize a listed species or its essential habitat or cause adverse modification of a Natural Area."

317. USEPA has failed to comply with 40 CFR 52.21(s) and to coordinate with other federal agencies that must still meet their obligations under the National Environmental Policy Act

before this project can proceed. There are several "actions" by other federal agencies associated with this project that might trigger the National Environmental Policy Act and the obligation to prepare an Environmental Impact Statement (EIS). For example, issuance of permits for water intake and discharge structures by the US Army Corps of Engineers could require an EIS. Certain actions by the Federal Energy Regulatory Commission approving transmission lines also may require an EIS. To the extent any of these permits have been issued, they must be reopened and coordinated with the issuance of the PSD permit. To meet its obligation, USEPA must first require Prairie State to disclose, and then independently confirm, all the federal approvals, permits, and other "federal actions" that may be necessary to construct and operate the proposed plant. Second, USEPA must fulfill its nondiscretionary duties under 40 CFR. 52.21(s) and Section 309 of the Clean Air Act. The Illinois EPA cannot fulfill USEPA's obligations to coordinate with other federal agencies.

As this comment addresses responsibilities of USEPA, which the Illinois EPA cannot fulfill, this comment should be directed to USEPA. However, it should be noted that 40 CFR 52.21(s) only requires coordinated review "…to the maximum extent feasible and practical." It does not establish the mandate for coordination suggested by the comment. In addition, this comment does not identify any federal actions associated with the proposed plant that would require the preparation of an EIS, and, instead merely speculates that such a requirement might exist. Finally, Section 309 of the Clean Air Act does not place any obligations on federal agencies other than USEPA. Thus, it is improper to suggest that any permits issued by other federal agencies need to be reopened.

318. The scope of the environmental impact analysis under the PSD program is akin to that required under the National Environmental Policy Act (NEPA). Congress exempted NSR permitting and other Clean Air Act actions from the requirements of NEPA on the basis that the Clean Air Act provides a "functional equivalent" of the analysis that would otherwise be required under NEPA. See Energy Supply & Environmental Condition Act, Section 7(c)(1), 15 USC 793(c)(1), see also, State ex re. Siegelman v. United States EPA, 911 F.2d 499, 505 (11th Cir. 1990) ("We see this express exemption [of CAA actions from NEPA] as Congress' way of making more obvious what would likely to occur as a matter of judicial construction"). There are similar analyses required under MACT.

The Illinois EPA ensured that Prairie State complied with the requisite Clean Air Act permitting requirements, including the BACT top-down analysis. In its October 2002, Updated Permit Application, Prairie State ranked the available technologies and appropriately selected BACT in accordance with the regulations and as outlined in the NSR Manual. In particular, the application and supporting materials document the BACT selection process. The emission control equipment for Prairie State is very efficient and is designed to handle emissions from combustion of unwashed high sulfur, high ash coal. The air quality analyses performed for the proposed plant will comply with all applicable standards that protect air quality.

General Concerns about Emissions from Coal-fired Power Plants

319. I am concerned about the proposed plant because of all the mercury that it will put in the air. Illinois residents have been warned not to eat fish from Illinois waters because of excessive levels of mercury, a byproduct of coal-fired power plants.

<u>Existing</u> coal-fired power plants contribute significant amounts of mercury to the environment through their emissions. However, the proposed plant would be equipped with modern emission control and emit a fraction of the mercury currently emitted by existing plants per megawatt of electricity produced. Significant reductions in mercury emissions and mercury levels in fish will require application of similar control measures to existing power plants on a national basis. In this regard, on March 15, 2005, the USEPA adopted a rule that addresses mercury emissions from coal-fired power plants that is expected to reduce their overall emissions of mercury by nearly 70 percent. Even then, the magnitude of the reduction in mercury levels in freshwater fish is uncertain, as transport of mercury emissions occur on a global scale.

Given these circumstances, it is important that people be aware of and understand the advisories that are issued by the State of Illinois on consumption of fish caught from Illinois waters because of the levels of mercury or other contaminants. In particular, Illinois issued its first statewide advisory for mercury contamination in 2001 as a protective measure given new studies indicating that consumption of fish with high mercury levels may pose a greater risk than previously thought for sensitive populations. These sensitive populations are children younger than 15 years of age and women who are or may become pregnant, to protect the unborn and nursing infants. The statewide advisory recommends that such individuals eat no more than one meal per week of predator fish taken from Illinois' waters. In addition, more restrictive advisories were given for certain bodies of water, such as the Ohio and Rock Rivers and Kincaid and Cedar Lakes. Further information on the fish advisory for mercury, as well as for advisories for contaminants in fish other than mercury, is available from Department of Public Health: www.idph.state.il.us/envhealth/fishadv/specialmercury.htm.

320. The State of Maine is concerned about the proposed plant because Maine is subject to transported pollutants, including ozone and ozone precursors, PM, acid aerosols, mercury and other air toxics, from a broad geographic region. Maine and other northeastern states have made significant strides in reducing emissions of these pollutants within their borders through a wide range of control strategies that go well beyond Clean Air Act requirements. However, Maine continues to be impacted by particulate, mercury and regional haze, which is the result of transported pollution so that further regional control measures are needed to achieve air quality goals in Maine.

    Despite the aggressive emission controls being required of the proposed plant, this plant would still have the potential to emit substantial amounts of emissions. Of particular concern are the mercury emissions, as mercury levels in Maine's fish, loons, and eagles are already among the highest in North America. In conjunction with this plant, other new coal-fired power plants in states east of the Mississippi River (where 40 new coal-fired power plants are currently planned or under discussion) could have significant impacts on air quality in Maine. The only way new power plants, such as the proposed plant, can be built without posing such a threat is through the establishment of a regional multi-pollutant control program for emissions of SO_2, NOx, mercury, and CO_2, with stringent emission control requirements for all power plants and other major industrial sources, along with state-wide caps on total emissions.

The Illinois EPA supports the efforts at the national level to adopt or enact comprehensive, stringent control requirement for power plants. (Refer to "Fossil Fuel-Fired Power Plants: Report to the House and Senate Environment and Energy Committees," Illinois EPA, September 2004.) However, the absence of such a multi-pollutant control program would not be a legal basis to deny a permit for the proposed plant, especially as emissions from this plant are better controlled than those of existing power plants and its emissions would be covered by any such program.

321. The proposed plant should not be allowed to emit dangerous levels of mercury. Mercury levels are magnified up through the food chain, so that the levels of mercury in predator fish can be a million times greater than the level in the water body. This threat could be significantly reduced if the plant is required to use state-of-the-art control devices. Mercury emissions from the proposed plant can be expected to be deposited both close to and at great distances from the plant. USEPA reported that between 7 % and 45 % of emitted mercury is deposited within 33 miles of the stack. Consequently, the proposed plant's mercury emissions are a direct threat to the residents and wildlife close to the plant site, as well as further a field. Based on USEPA's findings and other studies confirming those findings, the Illinois EPA should not grant a permit that would allow the proposed plant to emit 280 pounds of mercury annually. To do so would allow the plant to emit mercury at levels that would constitute air pollution as they threaten human health and the environment.

The proposed plant is not being allowed to emit "dangerous levels" of mercury, as suggested by this comment. It is required to use modern control technology that would minimize its contribution to mercury contamination in the environment, both locally and globally. The conclusions about local deposition of mercury drawn in the comment are false, as they fail to address the total contribution to local mercury levels. The comment presumes that because some mercury emissions from the proposed plant would be deposited locally that a "hot spot" would result. However, USEPA has not concluded that local deposition from a new coal-fired power plant will result in a hot spot. Indeed, research also indicates that much of the mercury emissions from power plants in the United States does not deposit within the continental United States. At the same time, much of the mercury deposited in the United States originated elsewhere.

322. To minimize mercury emissions, the permit should limit all coal to Midwestern bituminous coal. The draft permit errs when it fails to consider public-health costs and benefits and does not require coal used at the plant be Midwestern bituminous. There is neither a reliable benefit-cost nor public-health rationale for this omission. Further, failure to require that only this type of coal be used would further put children and pregnant women at greater risk.

As explained in another response, the proposed plant is effectively limited to Midwestern bituminous coal, as generally recommended by this comment. However, as a matter of policy, it is appropriate to establish a comprehensive approach to control of mercury on a national basis that properly and fairly addresses all types of coal. This is because different power plants will continue to use different types of coal given their location and circumstances, including the selected approach to environmental compliance.

323. The problem of mercury contamination in aquatic ecosystems in Illinois remains a stubborn challenge. Despite reductions in the release of mercury from other source sectors, coal-fired power plants remain a major contributor to this contamination. Illinois' coal-fired power plants produced 80 percent of the mercury emissions in Illinois. An aggressive approach to the reduction if not elimination of mercury emissions is needed to reduce the mercury levels in fish.

The Illinois EPA shares the sentiment expressed in this comment.

324. Existing coal-fired power plants are Illinois' largest sources of air pollution, aggravating respiratory and heart disease and even causing premature deaths. According to material prepared by the USEPA in its enforcement case against the Baldwin power plant, emissions from that plant are responsible for a significant number of premature deaths that would have been greatly reduced if the emission controls on the plant had been upgraded, which USEPA believes should have occurred when changes occurred at the plant that USEPA alleges were modifications of the plant.

The emissions of existing coal-fired power plants are of concern, as generally expressed in this comment. However, the emissions of vehicles, including cars, trucks, trains and heavy off-highway equipment, generally pose similar concerns, and represent as a group about 40 percent of all air pollution. While the emissions of individual vehicles are generally small, depending upon type of vehicle and age, the total number of vehicles and the low height of discharge also make them an important category of source for ambient air quality in urban areas. It is important to be aware of the contribution of all pollution sources when making judgments about particular classes of sources.

The Illinois EPA is also dubious of the allegation attributed to USEPA in the separate lawsuit. Such allegations may frequently occur in the context of contentious litigation but they should not be relied upon as either proof of legal causation or scientific fact.

325. Cases of asthma are on the rise, and it appears that at least some of the increase can be attributed to emissions from coal-fired power plants.

The observation in this comment is not supported by the actual facts. Since 1970 to the present, when reported cases of asthma have reportedly been on the rise, emissions from power plants have been substantially reduced and air quality has improved significantly.

Another comment submitted on the subject of asthma pointed to the many studies that have found that pollution-derived particulate in outdoor air has little relationship to the

prevalence, occurrence, or severity of asthma. Various studies have found neighboring communities in the same air shed with essentially identical air quality, with widely disparate asthma hospitalization rates. Studies show that asthma incidence and predisposition to allergic reactions is increasing even though air quality is improving. One hypothesis is that this phenomenon is unrelated to outdoor, ambient air quality but is instead due to changes in lifestyle and "energy conservation", which are increasing exposure to indoor allergens. Geographical variations in asthma hospitalization rates also show sharp differences that cannot be attributed to differences in ambient air quality. In Europe, asthma rates appear lower in more polluted regions than in regions with cleaner air. Research conducted in New York City has found that asthma prevalence correlates strongly with socioeconomic status, with several factors linked to poverty. Specific factors that related to asthma risk in low-income areas were the number of occupants per household (related to bacterial and viral exposures), water leaks (fungal exposures), deteriorating building materials (fungal and mite exposures), and house dust exposure (insect parts, animal dander, and rodent excreta).

326. Prairie State has not assessed the impacts of the proposed plant on PM2.5 air quality. Such action is not dependent upon the USEPA's designation of PM2.5 nonattainment areas, and does not eliminate the State's responsibility. USEPA's current guidance addressing PM2.5 is not legal and is not relevant to the Illinois EPA's obligation to protect public health. The Illinois EPA must at least take action to protect Illinois residents from the documented health effects of fine particles and prevent the risks attributable to increased exposure to fine particulate.

PM2.5 air quality is addressed in terms of those pollutants that contribute directly to PM2.5 air quality. By establishing BACT controls and work practices for PM, SO_2 and NOx, the permit will provide BACT for emissions of PM2.5. It should be noted that this type of surrogate approach in achieving a BACT level of controls is not unprecedented. The overall impact of the proposed plant is addressed by the existing programs that regulate power plant emissions, i.e., the federal Acid Rain Program and the NOx Trading Program, which were recently supplemented by USEPA with CAIR. Beyond this, the residents of Illinois are generally protected by the process that starts when an area is designated nonattainment, which requires the State to take needed measures to reduce emissions, improve air quality, and bring the area into attainment. This process includes a detailed evaluation of the role that different sources and categories of sources have in contributing to nonattainment status, so as to allow a comprehensive set of control measures to be developed that will prove both effective and feasible in achieving the ultimate result of attainment. This detailed evaluation is a critical step in the process, as the contribution of sources to nonattainment status may be affected by their location and influenced by specific sets of meteorological conditions, so that certain reductions in emissions are more effective in actually improving air quality for PM2.5.

Incidentally, USEPA has not issued guidance for implementation of the PM2.5 standard, even in draft form. Accordingly, it is unclear to which particular document this comments refers when it claims that USEPA's current guidance addressing PM2.5 is illegal.

Permit Provisions - Flexibility/Scope

327. Use of solid fuels other than coal in the boilers should be prohibited. However, the draft permit would allow the coal-fired boilers to burn "any solid fuel" as long as Prairie State first gives 30 days prior notice to the Illinois EPA. A permit provision that authorizes the use of alternate fuels without a permit modification and without opportunity for public comment is unlawful. There would be no opportunity for oversight by USEPA or opportunity for appeal to the EAB.

In response to the further consideration triggered by these comments, the issued permit does not provide for use of fuels other than coal and natural gas in the boilers. At the same time, this comment does reflect an underlying approach to the PSD permit process that closer examination does not support. While certain proposed changes to a source may constitute major modifications for which a PSD permit is required based on the capabilities and circumstances of the source, this does not mean that a PSD permit needs to be crafted in such a way that any alternative mode of operation must be considered a major modification, i.e., as triggering a requirement for a revised PSD permit. Another broad principle of air pollution control regulations is that the operators of sources should have broad flexibility to utilize installed equipment provided that equipment complies with applicable emission standards and is being operated within the original, installed capabilities of the equipment or in a way that emissions do not increase, i.e., the source is not being modified.

328. Condition 1.9 in the draft permit would unlawfully allow Prairie State to construct a different source than the source proposed in the application and authorized in the permit. This could occur merely by providing notice to the Illinois EPA, without obtaining further Illinois EPA approval, without modifying the existing permit and without any opportunity for public comment. Perhaps most troubling, under Condition1.9(d), Prairie State could reduce the capacity of the plant with no reduction in its air quality impacts.

The condition addressed by this comment has not been included in the issued permit. In accordance with the EAB's March 25, 2005 order, this action was taken to eliminate an issue on which the permit would likely be appealed to the EAB.

It should be noted that this comment misinterprets this condition in the draft permit, which would not have allowed Prairie State to build a different source. The provision in question merely would have recognized that Prairie State could build a smaller plant with less capacity. The comment also incorrectly assumes that any such reduction in the capacity of the plant would not result in lower impacts on air quality. However, any reduction in the capacity of the plant would result in an equivalent reduction in permitted emissions and as such, directly act to reduce the plant's overall impacts on air quality. This is because BACT limits are generally set in relative terms, e.g., lb/million Btu heat input or percent control efficiency, not absolute terms, i.e., lb/hour.

329. If the Illinois EPA has any evidence that Prairie State may wish to build a different size source than that described in its application, the Illinois EPA must disclose that information and refuse to proceed with permitting pending a commitment from Prairie State to build the

specified size plant. The EAB describes in In re Inter-Power of New York, Inc., 5 EAB 130 (Mar. 16, 1994), how doubts about a commitment to build the exact facility led it to order Interpower "... to affirm that it is presently committed to construct the ... facility for which it received a PSD permit or show cause why the permit should not be denied on the grounds that it does not intend to construct the facility identified in its permit application."

The Illinois EPA has no information indicating that Prairie State wishes to build a plant with a capacity different than that described in its application.

330. The size of a source can make a significant difference in the BACT analysis. For example, USEPA, Region 2, rejected petitioners' argument in the permitting for Inter-Power of New York to consider a more stringent PM BACT limit for a certain source on the basis that the source was not an appropriate example because it was much smaller, i.e., USEPA was saying that a smaller source could have a higher PM limit than a larger source.

The Illinois EPA concurs with this comment. However, as noted in the comment, a determination of BACT for a smaller unit may not be as stringent as the determination of BACT for a larger unit. This does not mean that a stringent BACT determination for a large unit cannot be appropriately relied upon as a determination of BACT for a smaller unit.

331. The permit should be issued with minor wording changes so that any fuel substitutions because of temporary disruption or interruption in the mining operations are (1) time-limited, and (2) still limited to Midwestern bituminous coals, explicitly excluding sub-bituminous coal and lignite from the west. Otherwise, the wording of Conditions 1.3 and 2.1.14 in the draft permit might lead one to believe that long term non-emergency changes in the coal supply are authorized by these provisions. Limiting the type of coal that can be used during disruptions in mining operations is necessary to ensure that emissions will still be effectively controlled during such periods.

In response to this comment, the issued permit includes provisions to define interruptions in the operation of the mine during which an alternative source of coal could be used. These changes make clear that this term does not extend to incidents that can be addressed by maintaining a reserve coal pile or that can otherwise reasonably be avoided by Prairie State. Another change was to use the term "extended" interruption, rather than "temporary" interruption, as that better addresses the type of interruptions that are being addressed.
However, as noted in the comment, these provisions are intended to address disasters, emergencies and unforeseeable events that Prairie State clearly cannot prevent and other events that Prairie State may not be able to reasonably avoid or prevent, such as catastrophic failure of the mining operations or labor strikes. As such, it is not appropriate to further constrain the measures that the source can take in response to such an event by imposing specific "time limits," as the probability of such events is uncertain and their exact nature and circumstances are not known. Thus, the issued permit addresses the duration of these events in qualitative terms, by requiring Prairie State to undertake appropriate steps to restore the mine-mouth coal supply in a reasonable time, given the nature of the efforts that are needed to

accomplish this.

The further restriction requested in this comment with respect to the nature of the alternative coal supply likely applies as a practical matter. That is, boilers designed for bituminous coal cannot be switched to other ranks of coal without making certain physical adjustments to the boilers and Prairie State would be under an economic incentive to return to its regular, mine-mouth coal supply as soon as it was practical to do so, making it impractical to undertake such adjustments. Nevertheless, to assure that the coal supply to the boilers during extended interruptions is similar to the mine-mouth coal supply, the alternative coal supply is limited to Midwestern bituminous coal, i.e., Illinois No. 5 and No. 6 coal.

332. The draft permit's "restriction" on using coal from other sources is practically unenforceable. It would allow the plant to burn up to 5 percent "other" coal, yet the BACT analyses do not consider the air quality benefits of burning 5 percent low sulfur coal (or 5 percent petroleum coke).

These comments do not demonstrate that the provisions in the draft permit would have been practically unenforceable. In addition, while the proposed plant is designed as a mine-mouth facility for Illinois No. 6 coal, as with any power plant, if an interruption in the normal coal supply would stop operation of the plant, it is important as a matter of public policy that the plant have a reasonable ability to maintain operations with an alternative source of fuel. As such circumstances would not alter the applicable emission limits with which the plant must comply, the source of coal during such a fuel supply interruption would not be the primary consideration. Rather, the nature of the alternative coal would be the restricting factor as related to the plant's ability to continue to operate in compliance. Due to the technical and mechanical components of the boilers and air pollution control equipment, it is essential that any alternative coal used must have similar ash, heat content and combustion characteristics as the coal upon which the design of the boilers and the permit is based. Therefore, the proposed plant will be essentially restricted to burning coal from the Illinois No. 5 or No. 6 coal seams during interruptions in the mine-mouth fuel supply. As previously explained, the alternative coal supply during such periods must also be washed coal.

333. The restriction on use of "other coal" in the draft permit is flawed because it would not apply "during temporary interruption in the operation of the mine." Also, while the provision states that the acceptance of any non-mine-mouth coal would require a separate construction permit, it then undoes this by saying a permit is only necessary if the use of coal shipped by truck or train is the "principal" source of coal. This would allow Prairie State to take advantage of this provision for almost any reason. Does "temporary interruption" include holidays or any labor-related matters, such as workers seeking to organize a union?

This comment is no longer relevant given the changes to provisions of the issued permit, as compared to those of the draft permit, that have been made in response to comments. In particular, the issued permit more readily and precisely addresses the coal supply for the plant as a specific alternative coal supply is identified for the plant, i.e., washed Illinois No. 5 or No. 6 coal from other mines. In addition, this alternative coal supply can only be used in

certain narrow circumstances, i.e., during extended interruptions of the mine-mouth coal supply that could not have been reasonably prevented by the Permittee and that the Permittee is actively working to correct. . .

334. The Operational Flexibility Provisions for material handling operations are unlawful. Draft Permit Condition 2.2.14 would allow Prairie State to "construct and operate affected units that are different from those described in the application without obtaining prior approval by the Illinois EPA." This is simply unlawful. The safeguard in Condition 2.2.14(b) that such changes "shall generally act to improve dispersion and reduce impacts" is no safeguard at all.

This provision is appropriate to address developments that may occur during the design and construction of the material handling operations at the proposed plant. These may reasonably result in differences between the equipment and layout for these operations as conceptually set forth in the application and the ultimate design of these operations. The provision contains appropriate safeguards, most significantly that these operations must continue to comply with all applicable requirements established by the construction permit. In addition, minor changes in language have been included in the issued permit from the language in the draft permit, in response to this comment, to better describe the type of variation that is accommodated by the permit.

Permit Provisions - Compliance Procedures

335. The permit should require daily monitoring of PM and mercury emissions from the boilers. It is not appropriate that PM and mercury be tested only every three years. Moreover, it is impossible to satisfy the requirement of correcting emissions-equipment malfunctions as soon as possible if there is no daily monitoring.

The permit does require continuous emissions monitoring for particulate matter emissions from the coal-fired boilers, as a compliance assurance method associated with the control systems for particulate matter. This means that there will be continuous data for particulate matter emissions to assure proper operation of control equipment and prompt repair of any malfunction. It is also expected that the boilers will be equipped with continuous emissions monitoring systems for mercury, either as a result of USEPA rules or the case-by-case MACT determination in the permit, which requires monitoring for mercury emissions. However, the presence of this continuous monitoring does not eliminate the need for periodic emission testing as addressed by this comment.

336. The permit should have testing and monitoring requirements for particulate emissions from all operations at the plant, including the cooling tower, the gas fired auxiliary boiler and fugitive dust from roadways and other open areas.

The permit includes appropriate compliance requirements for these operations at the proposed plant. Given the nature of these operations and the types of control measures that are used, compliance procedures address proper implementation of control measures rather

than direct measurement of particulate emissions by testing and monitoring.

337. The permit should require Continuous Emissions Monitoring Systems (CEMS) for mercury. Such systems are the best means to verify compliance with requirements for mercury emissions.

The issued permit requires that mercury emissions from the boilers must be monitored if Prairie State must ultimately control mercury emissions pursuant to case-by-case MACT determination pursuant to Section 112(g) of the Clean Air Act. (Otherwise, the need to perform monitoring for mercury emissions is governed by applicable regulations adopted by USEPA for control of mercury.)

338. The permit should require correction of all emissions malfunctions within 48 hours. It is not reasonable to allow the Permittee to "correct [emissions] malfunctions as soon as practicable" (Condition 1.4(ii)). It makes little sense to require emissions malfunctions to be corrected as soon as practicable when, given the absence of reliable monitoring, it would be difficult to determine all emissions malfunctions.

The provisions addressed by these comments reflect USEPA regulations at 40 CFR 63.6(e) for actions to be taken in the event of malfunctions. The Illinois EPA believes that the approach taken by USEPA in these regulations is appropriate. The requirement to correct a malfunction "as soon as practicable" is a more stringent and fitting requirement than any fixed time-frame, which would have to be set for some unusual malfunction that entailed a minimal exceedance but was nevertheless resistant to speedy correction. The "soon as practicable" criterion can be appropriately tailored to the particular incident and the context in which it has occurred. A general requirement to correct malfunctions, i.e., properly operate and repair equipment, is also fitting for the proposed plant independent of the monitoring required for specific emission units, which is a separate matter from the provision at issue.

Other Permit Provisions - Miscellaneous

339. Because of the inadequacy of federal and state laws, the permit should include explicit provisions for "whistleblower protection." This includes protection for all employees from retaliation for both complaints related to environmental compliance and the safety and health of working conditions. Otherwise, valid concerns are not as likely to be expressed and those who do express concerns are likely to experience retaliation. It is essential that the permit provide such protections because whistleblowers at the plant would face special obstacles arising from the fact that the area surrounding the plant is both low in income and high in unemployment. Both factors contribute to a greater potential for uncorrected safety threats.

The Illinois EPA does not possess authority to impose broad "whistle-blower" protections in the permit for the proposed plant as recommended by this comment. However, the Environmental Protection Act (Act) already includes provisions protecting whistle-blowers.

The Act specifically prohibits any person from firing or causing the firing, or discriminating or causing discrimination against, an employee or representative based on the filing of a legal proceeding, elicited testimony or the offering of evidence relating to any violation of the Act. The Act also outlines a remedial scheme by which whistle-blowers may seek a review of any purported retaliation or discrimination before the Illinois Department of Labor.

Environmental Justice (EJ)

340. Because the area surrounding the proposed plant is low income, it presents potential concerns for EJ. This area represents a classic picture of an EJ threat, people's bearing disproportionate levels of workplace and public pollution because of local poverty levels. To address these concerns, the permit should include provision for a community benefits agreement. This agreement should include funding for community-managed emissions monitoring, which has proved successful for other EJ projects in building community trust. In addition, workers need to have a role in assessing and evaluating the relevant risks associated with sources such as this one.

In fact, the area surrounding the proposed plant does not present the circumstances indicated in this comment and does not pose concerns for EJ. Low-income communities are actually located many miles from the plant, at distances with which other, more affluent communities are interspersed. This means that residents of low-income communities would not experience air quality impacts from the plant that are different than those experienced by residents of more affluent communities. However, the Illinois EPA would still encourage Prairie State to work openly with the local community, to address its concerns and interests. This is appropriate for all sources, even when they are subject to extensive requirements for emission testing and monitoring, like the proposed plant.

341. For the Onyx commercial incinerator in Sauget, USEPA is conducting an EJ assessment to address potential impacts on nearby minority and low-income communities, including East St. Louis. This assessment should be expanded to include the impacts of the proposed plant, as well as two other large mercury-emitting proposals: the Holcim cement plant in Missouri and the expansion of the Baldwin plant. This is necessary to ensure that the proposed plant, in combination with these two other projects, does not cause disproportionate impacts on low-income or minority populations.

The Illinois EPA does not believe that the USEPA's EJ assessment for Onyx is relevant to the proposed plant, as Onyx and the communities of concern for Onyx are over 30 miles away from the site of the proposed plant. However, this comment has been referred to the USEPA. The Illinois EPA is committed to working with USEPA to evaluate and address any adverse impacts in and around the Metro-East area attributable to Onyx or any other plant.

342. The Illinois EPA has failed to comply with its EJ obligations, which require consideration of EJ implications in permitting decisions. The Illinois EPA must comply with its EJ obligations and ensure that the proposed plant does not cause disproportionate impacts on

low-income or minority populations. This should include consulting with local and state health departments about the existing problems and ways to ensure there are no disproportionate impacts as a result of the proposed plant.

As stated in the Illinois EPA's "Environmental Justice (EJ) Policy," the Illinois EPA is committed to ensuring that all residents of Illinois, regardless of race, culture, or income, have the same degree of protection from environmental and health hazards. However, disproportionate impacts on EJ communities have not been identified from the proposed plant. USEPA considers "environmental justice communities" as "a minority or low-income community that bears disproportionately high and adverse human health or environmental effects." (Executive Order 12898.)

The Illinois EPA has evaluated demographic data from USEPA's EJ Geographic Assessment Tool for the area surrounding the proposed plant, including the community of Marissa. This data shows that this area is not a minority or low-income area and has levels of minority population and poverty that are the same or lower than the statewide averages. The data from counties located within the significant impact area identified and modeled for the proposed plant also shows that the plant does not raise issues for EJ. Of the six counties located in the significant impact area, only St. Clair County has a minority population above the statewide average. St. Clair County is also the only county with a poverty level greater than the statewide average. There is no evidence that residents of St. Clair County would bear a disproportionately high and adverse impact compared to the residents in the five other counties in the impact area. Moreover, the significant impact area, i.e., the area as identified in the air quality modeling conducted by the plant within which more than a trivial impact is predicted, does not cover the entirety of these six counties. East St. Louis, accounting for a large proportion of St. Clair's County's minority population, is located outside of significant impact area. As related to the USEPA's guidance for EJ, this means that the proposed plant's emissions do not pose a concern for disproportionate impact because such impacts, if any, are so small as to be trivial.

343. Recent news reports indicate that Prairie State is not proposing to provide electricity for local residents and thereby will not displace existing power plants. Instead, Prairie State is seeking to sell power to far-away places such as Michigan, Missouri and Indiana. The residents of Metro-East face the prospect of receiving no benefits from the plant; just increases in air pollution. EJ concerns for the proposed plant cannot be downplayed by asserting that the plant will result in fewer emissions because it will displace existing, old coal-fired power plants.

Because of national programs to control emissions, notably programs addressing motor vehicles and fuels, improvements in air quality will continue to occur for residents of the Metro-East independent of whether the proposed plant is built and who it serves. In addition, the NOx and SO_2 emissions from coal-fired power plants, including those of the proposed plant, are restricted by the NOx Trading Program and federal Acid Rain Program irrespective of who is purchasing the electric power from the plants. Prairie State has also committed to buy additional SO_2 allowances under the Acid Rain program until new regulatory programs are enacted for power plants. This commitment, which is now binding

on Prairie State, generally acts to ensure that the proposed plant will be accompanied by a net decrease in SO_2 emissions from power plants until new programs are in effect that specifically require further reductions in emissions.

Public Comment Period

344. The public notice was inadequate. It did not include SO_2 annual increment consumption and did not explain that certain modeled concentrations exceeded the NAAQS. The notice needed to inform the public that the highest predicted SO_2 values were 649 ug/m^3, 24-hour average, and 2639 ug/m^3, 3-hour average, values that are higher than the health based SO_2 NAAQS. Also, the PM increment value reported is just the proposed plant's impacts rather than the cumulative PM increment consumption. This is very important because the increment in Randolph County is fully consumed. This should mean no growth without additional reductions and Illinois has to modify its State Implementation Plan. For PM10, Prairie State modeled a high second high of 45.2 ug/m^3, 24-hour average, compared to the increment of 30 ug/m3.

     The draft permit also is misleading as Finding 6(a) states that the air quality analysis shows compliance with the allowable increment levels. However, even under Illinois EPA and Prairie State's analysis, this statement should really say that the Prairie State's modeling showed that the allowable increment levels for PM10 and SO_2 were fully consumed but that the proposed plant would not contribute significantly to the receptor and time combinations for which violations of the increment were shown.

The public notice and draft permit conveyed significant details of the air quality analysis so as to allow meaningful public comment. The matters addressed in this comment involve a level of detail that is beyond the proper scope for a public notice. They further involve the commenter's opinion about how the results of the air quality analyses for the proposed project should be interpreted and explained.

345. The Federal Land Manager (FLM) for the Mingo Wilderness Area has objected to the draft permit because the project would have adverse impacts on Mingo. However, the Illinois EPA has still not given public notice of the FLM's official finding. The Illinois EPA must notify the public of the FLM's finding of adverse impact and provide a new comment period.

As discussed elsewhere, the public notice included appropriate information addressing the comments provided by the FLM prior to the beginning of the public comment period.

346. Relevant documents were not available in a meaningful manner. The efforts of Illinois EPA staff to provide information were appreciated. However, the process of having to ask certain staff for each item we want and then staff having to contact the consultant on occasion to obtain the relevant documents is not a workable system considering the amount of information that needs to be reviewed and the limited time to review it. In addition, Prairie State's submittal of information during the comment period, such as the Screening Level Ecological Risk Assessment and the April 19, 2004 Additional Information Submittal, is

contrary to Section 165(a)(2) of the Clean Air Act.

The concerns expressed in this comment do not invalidate the public comment period held for the proposed plant. The ability of the Illinois EPA to readily respond to specific questions about a proposed project is different than the availability of the submitted application. The submittal of additional assessment by Prairie State for purposes of the Endangered Species Act is a separate matter from the air quality analysis that was submitted to address air quality requirements under the PSD rules. Likewise, the submittal of material responding to comments is appropriate as one function of a public comment period is to develop additional material that responds to concerns expressed by the public about a proposed project.

347. The permitting of the Prairie State project has not been an open and accessible process. The public has the right to know the details of a new source that is proposed for approval in a manner that affords adequate time for review and submittal of comments. Some of the blame for the process rests with Prairie State, which failed to provide the necessary information in its application about the potential impacts on air quality and natural resources. However, the Illinois EPA and USEPA have the ultimate responsibility for keeping the permitting process open and have not taken steps to coordinate public comment for all the necessary environmental permits for the proposed plant in a meaningful manner. A fragmented review process is a benefit to Prairie State and a dereliction of your obligations.

The Illinois EPA should reopen any issued permits and provide a coordinated permit process that provides the public with information that is meaningful, such as the results of the ESA consultation process. The public comment period should not close until Prairie State has submitted all necessary information required for a complete application, and the USEPA and Illinois EPA have completed their obligations, including complying with endangered species laws, the National Environmental Policy Act, and other applicable laws. Only then will the public have the information necessary to fully review and comment on the proposed plant. In short, the agencies must ensure that the application is complete, that the draft permit incorporates the completed application information before holding a public hearing and closing the public comment period. In this case the sole public hearing was held long before the application was complete, before the endangered species laws were complied with, before any coordination pursuant to NEPA.

The permit application, draft permit, project summary, and the public notice were all made available in accordance with all applicable procedural regulations. In addition, this material was made available in different formats (paper, computer CD, or e-mail) to accommodate the viewing method preferred by various individuals. The Illinois EPA made tremendous efforts to provide the required documents, in the requested format. The Illinois EPA considers that there was ample time provided to the public to review the documents in the record. In addition to the 75 days required by the Illinois EPA's hearing regulations, 35 IAC 166, the Illinois EPA provided more than four months in additional time for the public to review documents and submit comments.

The Illinois EPA does not have the authority to delay the review of permit applications, whether air, water, or land, to coordinate with the review of other permit applications that

may be needed for a project. Illinois EPA cannot hold up action on one application based on the status of another application. The Illinois EPA extended the public comment period five times to facilitate further review of information and submission of additional comments. Moreover, there are benefits to separate permits under distinct regulatory programs. A staggered process simplifies public review of the various aspects of the proposed plant, concentrating attention on one aspect at a time.

348. The current public access process is unfair and should be improved. The record must, of course, be provided at a public repository close to the proposed site. However, with a coal-fired plant and its significance for air quality, similar access should be provided for people living far from the proposed site. This could be accomplished with a website that has all of the record associated with a project. Only then can the public be sure that it is looking at the same material as the Illinois EPA.

The Illinois EPA appreciates the importance of public availability of documents, as addressed by this comment and will continue to make improvements to its procedures in this regard. For example, for the Prairie State application, for the first time, copies of an application were made available on CD, as well as in paper form depending on the preference of individuals. Also, the Illinois EPA went far beyond its legal obligations by sending material to anyone requesting it, by having material in a local repository (which is not mandatory) and by posting Illinois EPA generated documents on the Internet. While the Illinois EPA would have liked to post the application on the Internet, this is something that could not be accomplished with current capabilities and resources. Also, several files were too large to be efficiently downloaded. Accordingly, the Illinois EPA chose to provide the application on CD to those who wanted it in an electronic format.

349. Prairie State's consultant's handling of modeling files, including failure to describe the sources included in different modeling runs, is very confusing. It made review impossible for the general public and very difficult even for those with a technical background. Prairie State should be required to complete its submittal of information before the comment period begins and then all modeling files that the Illinois EPA is relying on as the air quality analysis for the proposed plant be placed on an Internet site with a labeling system that is understandable. This would allow a meaningful opportunity for public comments on the modeling conducted for the proposed plant.

The concerns expressed in this comment do not invalidate the public comment period held for the proposed plant. Air quality dispersion modeling is a technical matter for which some familiarity with modeling procedures is needed if an individual is going to submit meaningful comments on the details of modeling for a proposed project. The actions of Prairie State to submit comments with additional modeling that was responsive to comments were appropriate, and are indicative of an effective public participation process. One function of a public comment period is to develop additional material that responds to public concerns about a proposed project.

350. If the Illinois EPA does not deny the permit but instead makes changes to the draft permit, another comment period is requested in order to consider the changes.

The Illinois EPA will not hold another comment period pursuant to this request. Changes have not been made in the issued permit, whose nature warrants a further public comment period. Rather, provisions of the permit have been changed in response to the comments that were received from the public, or in response to the Remand Order issued by the EAB, so as to generally make the requirements for the proposed plant more stringent.

Public Health

351. USEPA has found that various health effects, such as the increased incidence of pulmonary and cardiovascular disease symptoms, increased hospital admissions, and premature mortality, could be expected to increase in response to increased exposure to fine particulate. However, Prairie State has not assessed the impacts of the proposed plant on PM2.5. USEPA's failure to provide guidance for PM2.5 nonattainment areas does not eliminate the State's responsibility to protect Illinois residents from the health effects of fine particulate. Furthermore, USEPA's current policy for addressing PM2.5 is not legal and is not relevant to the Illinois EPA's obligation to protect public health. The Illinois EPA must at least take action to prevent the health risks attributable to increased exposure to fine particulate that are documented in the USEPA's 1996 Criteria Document. Prairie State should assess PM2.5 primary emissions from the proposed plant and estimate the rate of secondary PM2.5 precursor conversion. These emissions should be modeled to estimate the effect the plant's emissions will likely have on ambient PM2.5 concentrations.

Washington County was recently designated an attainment area for PM2.5, effective April 6, 2005. Based on experience with PM2.5 air quality elsewhere, air quality in the area near the plant will not be threatened by the plant. In particular, the monitoring station near the Baldwin power plant routinely records some of the best air quality in Illinois for PM2.5.

This can be confirmed by a simple analysis using air quality modeling data for the proposed plant and existing ambient monitoring data that is available. In particular, while primary PM2.5 impacts of the proposed plant were not explicitly modeled, the impacts of the particulate matter emissions of the boilers, the key units for purposes of PM2.5 air quality, can be estimated from the SO_2 impacts that were determined. This yields maximum PM10 impacts of 1.75 ug/m3, 24-hour average, and 0.06 ug/m3, annual average, calculated from the maximum SO_2 impacts of the boilers (21.00 ug/m3, 24-hour average, and 0.67 ug/m3, annual average) and the ratio of permitted PM10 and SO_2 emissions from the boilers (261 lb/hr and 3,126 lb/hr). These PM10 impacts are below the significant air quality impact level for particulate matter established by USEPA under the PSD rules, which would indicate that this analysis need not be pursued any further. Nevertheless, these "PM10" impacts can then be added to the maximum PM2.5 air quality levels recorded at the ambient monitoring station near Baldwin during recent years, conservatively assuming that all the particulate matter emitted from the boilers is PM2.5. The results show attainment of both the daily and annual air quality standard for PM2.5. On a daily basis, the maximum concentration is 38.1 ug/m3 (1.75 + 36.3 = 38.1) compared to the standard of 65 ug/m3. On an annual basis, the maximum concentration is 13.5 (0.06 +13.4 = 13.5), compared to the standard of 15 ug/m3. While this analysis does not assess the impact of emissions of SO_2 and NOx from the boilers, as SO_2 and

NOx are precursors to PM2.5, this is not necessary to assess the maximum impacts of the plant on PM2.5 air quality by itself. This is because SO_2 and NOx react gradually in the atmosphere, over hours and days, to convert to PM2.5. In addition, SO_2 and NOx emissions from the plant will be accompanied by reductions in SO_2 and NOx emissions from other existing power plants, first as a result of the existing Acid Rain Program and NOx Trading Program, and then by CAIR. In this regard, the regulatory programs for power plants now generally focus on the aggregate or cumulative effect of the emissions of power plants on PM2.5 air quality, not the effect of individual power plants, like the proposed plant.

Given the nature of the actions that must now occur because the greater St. Louis area has been designated nonattainment, there is not a reasonable basis to conduct any further analysis of the effect of the proposed plant on PM2.5 at this time. Nor is one needed to protect against increases in PM2.5 air quality. Most significantly, the plant would not actually begin operation for a number of years, so that current emission levels and air quality is not indicative of what conditions will be when the plant begins operation. This is relevant because designation as a nonattainment area immediately sets in motion a process to lower emissions and improve air quality. It is also relevant as programs are already in place to reduce emissions in urban areas that over time are improving air quality, such as the motor vehicle emission control program. In addition, emissions of power plants on a national and regional level are already restricted by the Acid Rain program and the NOx Trading Program, and will be much more tightly restricted in the future by CAIR, so that the analysis must appropriately account for the effect of these broad restrictions on power plant emissions when considering any effect of the proposed plant on PM2.5 air quality. Most importantly, Illinois and Missouri will have to develop and implement a plan to meet the PM2.5 air quality standards, fully considering the changing conditions in the area, so that any contribution of the proposed plant on PM2.5 air quality is appropriately addressed and accounted for.

352. Many researchers have studied whether air pollution in general, and emissions from fossil fuel-fired power plant specifically, harm public health. The first approach to studying the effects of exposure to particulate (and many other pollutants) is to apply the methods of toxicology and quantitative health risk assessment to the specific components of particulate. Evaluations using these methods indicate that the types and amounts of pollutants emanating from well-controlled coal-fired power plants, like the proposed power plant, pose no significant risk to public health. The predominant forms of PM2.5 produced by their emissions are ammonium sulfate and ammonium nitrate. These compounds are formed in the atmosphere, over time, from the SO_2 and NOx emitted by the plants. At typical concentrations, airborne sulfates and nitrates are essentially nontoxic in both laboratory animals and humans. Other specific components of particulate have been assessed toxicologically, including diesel engine exhaust. While some of these components have been found to be more potent that sulfate and nitrate salts, they are emitted from power plants at far lower levels and contribute to the ambient air at far lower concentrations.

The National Ambient Air Quality Standards (NAAQS) are established by USEPA to protect human health and welfare and the environment based on careful review of scientific research and study. Fine particulate matter is both emitted directly and formed in the atmosphere through complex chemical reactions among precursor pollutants, primarily, NO, SO_2,

ammonia, and ozone. Reductions in emissions of these precursors pollutants will result in reduced levels of PM2.5 in the ambient air. Coal-fired power plants are significant sources of NOx and SO_2 emissions, and therefore do contribute to levels of PM2.5 in the air.

There are no provisions that would allow a risk-based approach to be used to differentiate between the significance for public health of PM2.5 emissions attributable to power plants and the emissions of PM2.5 from other sources. In addition, emissions of power plants are of concern as they contribute to air quality concerns other than PM2.5. However, this comment correctly notes that many other human activities contribute significantly to ambient air quality for PM2.5, including the operation of cars, trucks, and buses, and wood stoves and fireplaces among others, and may also pose other concerns for the environment beyond their contribution to PM2.5.

353. Scientific data does not support the common notion that moderate airborne concentrations of ordinary non-biological particulate cause or exacerbate asthma. Asthma is a chronic respiratory disease that is certainly a significant public health problem. At sufficiently high levels of exposure, many biological, chemical, or physical agents may initiate asthmatic responses with airway constriction in the lungs. These triggers can include viral respiratory infection, allergens (pollen, animal dander, mold, mites, cockroach components, and rodent excrement), exercise, weather (in particular, cold air), emotional stress, environmental tobacco smoke, and certain foods, drugs, or workplace chemicals. Current research and both medical and community efforts aimed at reducing the occurrence and severity of asthma in urban areas focus on many risk factors and care strategies including improving indoor air quality and access to quality health care. They generally do not focus on the study or assessment of low levels of ambient particulate. A major problem with the hypothesis that ambient PM is responsible for the prevalence of asthma is that over the last two decades when asthma rates have been increasing, airborne PM levels have been decreasing.

At noted in this comment, asthma is a serious disease that requires appropriate care and management. To assist asthmatic individuals and others who are particularly sensitive to ambient air quality, the Illinois EPA uses the Air Quality Index (AQI) to report air pollution levels on a daily basis. This allows individuals who may be affected by poor air quality to plan and adjust their activities appropriately. In Illinois, most of the orange days, in which air quality may affect sensitive individuals, are generally associated with ozone levels. With improvements in air quality, the number of orange days each year continues to go down.

FOR ADDITIONAL INFORMATION

Questions about the Responsiveness Summary and permit decision should be directed to:
Bradley Frost, Community Relations Coordinator
Illinois Environmental Protection Agency
Office of Community Relations
1021 North Grand Avenue, East
P.O. Box 19276
Springfield, Illinois 62794-9276
217/782-7027

LISTING OF SIGNIFICANT CHANGES BETWEEN THE DRAFT AND ISSUED PERMIT

Finding 1(b): This finding, which describes the fuel supply of the proposed plant, is revised to address operation of the plant during potential interruptions in the mine-mouth coal supply to facilitate the reliable operation of the plant. It recognizes limited circumstances in which the plant could use washed Illinois No. 6 coal or similar washed Illinois No. 5 coal from other mines in the Illinois Basin. This finding also explains that any coal used during such limited circumstances, other than mine-mouth coal, must be washed, as the analyses and evaluation completed for coal washing of the mine-mouth coal supply at the proposed plant are not applicable to the use of such other coal because the source(s) of such coal are not specified.

Finding 6(b): This finding, which addresses the impacts of the proposed plant on air quality related values on the Mingo Wilderness Area, is revised to address developments since the release of the draft permit, including enhancements made to the permit to reduce impacts of the proposed plant and the general nature of the Illinois EPA's final determination that the proposed plant will not adversely impact air quality related values at the Mingo Area.

Condition 1.3: This condition, which addresses the coal-supply for the proposed plant, is revised for clarity, consistent with the changes to Finding 1(b). It is also revised to remove provisions addressing use of alternative fuels, other than coal and natural gas, in the boilers.

Condition 1.5: The number of emergency diesel engines associated with fire pumps (two) is identified and these engines are required to be fueled with ultra low sulfur diesel fuel, rather than very low sulfur fuel oil.

Condition 1.9 (Draft): This condition, which would have explicitly addressed applicable procedures if Prairie State decided to reduce the size of the proposed plant, has not been included in the issued permit.

Condition 1.9 (New): This condition is added requiring Prairie State to retire 25 percent more SO_2 allowances than otherwise required under the Acid Rain Program until such time as additional requirements addressing SO_2 emissions from power plants become effective on a national or state level, such as the Clean Air Interstate Rule (CAIR).

Condition 2.1.2: For the coal-fired boilers, BACT limits for NOx and SO_2 for which continuous emissions monitoring is performed, are made applicable at all times, including periods of startup, shutdown and malfunction. For CO, for which continuous monitoring is also performed, an alternative BACT standard is set to address periods of startup and shutdown. The hourly emission limits for pollutants for which monitoring is not performed are identified as secondary BACT limits to address periods of startup, shutdown and malfunction, with emissions during such periods to be assessed using engineering analysis and calculations.

Conditions 2.1.2(b)(i)(B), 2.1.8(a)(iii), 2.1.8(b), and 2.1.17: A BACT limit for total PM10 emissions (both filterable and condensable PM10) from the coal-fired boilers is added to the permit, i.e., 0.035 lb/mmBtu, supplementing other limits related to PM10 emissions. The new limit for total PM10 emissions is accompanied by provisions in Condition 2.1.17 for future downward adjustment of the limit based upon the demonstrated performance of the boilers. Related changes are made to testing requirements for the coal-fired boilers, to require testing as necessary for the evaluation of PM10 emissions and to accommodate developments in the test methods for condensable PM10 that will improve their reliability and accuracy.

Condition 2.1.2(b)(ii)(B) and 2.1.11(c)(ii)(B): A BACT limit for SO_2 emissions from the coal-fired boilers, expressed in terms of control efficiency, is added to the permit, i.e., 98 percent control, applied on a rolling annual basis, total of 12-months of data, with uncontrolled SO_2 emissions determined from the sulfur content of the coal supply to the boilers. The limit also extends to all operation of the boilers, including startup, shutdown and malfunction events. Recordkeeping to specifically address this requirement is added in Condition 2.1.11(c)(ii)(B).

Condition 2.1.2(b)(iii): The BACT limit for NOx emissions from the coal-fired boilers lowered to 0.07 lb/mmBtu, from 0.08 lb/mmBtu as proposed by the draft permit. The limit also extends to all operations of the boilers, including startup, shutdown and malfunction events.

Condition 2.1.2(b)(iv)(B): An alternative BACT limit, i.e., 893 lb/hour, 24-hour average, is established for CO emissions from the coal-fired boilers to address periods of startup and shutdown.

Condition 2.1.2(c) and (d): Introductory language for the provisions for control of HAP emissions were revised to reflect USEPA's recent action adopting rules for mercury emissions from utility boilers pursuant to Section 111 of the Clean Air Act.

Condition 2.1.2(c)(ii)(A)(I) and Attachment 4: For the case-by-case MACT determination for mercury emissions from the coal-fired boilers, the proposed MACT compliance option expressed as an emission rate, in lb mercury/million Btu, is not carried over into the issued permit. Instead, the issued permit provides only two compliance options for mercury, either (1) achieve 95 percent control with co-benefit from the control devices otherwise installed on the boilers, or (2) use activated carbon injection or other similar sorbent for the effective control of mercury emissions. As a numerical MACT emission rate for mercury is not present in the permit for use of sorbent injection, additional provisions are included in Attachment 4 describing how effective use of carbon injection is to be determined.

Condition 2.1.7(a)(i): The limit for NOx emissions on an hourly basis, daily basis, is not applicable during startup and shutdown, as temperatures of the flue gas during such periods will be below the level needed for effective operation of the SCR. The BACT limit would still address such operation. Higher limits were set for emissions of lead and beryllium.

Condition 2.1.7(a)(ii): A lower daily limit for SO_2 emissions from the boilers is set, 2,450 lb/hour, to take effect after an extended shakedown period.

Condition 2.1.7(b)(ii): Temporary limits were set on annual emissions of SO_2 from the boilers, effective through calendar year 2010, reflecting commitments made by Prairie State to address concerns raised by USFSW.

Condition 2.1.8(a)(iv): The provisions for periodic testing of particulate matter emissions from the coal-fired boilers, after completion of initial testing, including the testing required for evaluation of total PM10 emissions are revised to address the presence of limits for total PM10, as well as PM. In addition, the maximum intervals between testing for particulate matter emissions are set at 30 months and 48 months, rather than 36 and 54 months. (The longer interval is applicable if the results of two consecutive tests are two thirds or less than the applicable limits for particulate matter, e.g., for PM, 0.010 lb/mmBtu or less, as compared to the limit of 0.015 lb/mmBtu.)

Conditions 2.1.9-2: A condition is added to the permit explicitly requiring continuous emissions monitoring for mercury to accompany operation under either compliance option of the case-by-case MACT determination for the coal-fired boilers. (The draft permit only required such monitoring if activated carbon injection were needed to control mercury emissions from the boilers.)

Condition 2.1.10(b), 2.1.11(b), and 2.1.12(b): Changes to the sampling and analysis requirements, recordkeeping requirements, and notification requirements for the fuel supply for the coal-fired boilers are made as use of alternative fuels is no longer addressed by the permit.

Condition 2.1.15: The provisions addressing installation of additional control measures on the coal-fired boilers are simplified.

Conditions 2.1.16(a)(ii): The provisions for evaluation of the daily SO_2 emission limit for the coal-fired boilers with likely reduction of such limit are simplified.

Conditions 2.2.2: Additional performance criteria are added for control of particulate emissions from material handling operations, such as coal storage piles and coal transfer conveyors, that will not be enclosed in buildings and ducted to filtration control type control devices, but will instead use dust suppression techniques to control particulate emissions. In addition, to improve clarity, the provisions for the storage piles, which will be in the open, have been separated from the provisions for coal transfer conveyors, which will be covered or enclosed.

Table I: Changes were made to this table, which states the permitted emissions of the coal-fired boilers, to reflect the various changes made in the body of the issued permit, and to clarify which short-term limits apply at all times, including startup and shutdown.

List of Abbreviations

Btu	British thermal unit
g	gram
lb	pound
km	kilometer
mmBtu	million British thermal units
m^3	cubic meter
MW	megaWatt
MW-hr	megawatt- hour
s	second
ug or µg	microgram

List of Acronyms

AQRV	Air Quality Related Values
BACT	Best Available Control Technology
CAIR	Clean Air Interstate Rule
CEMS	Continuous Emissions Monitoring System(s)
CFB	circulating fluidized bed
CFR	Code of Federal Regulations
CO2	carbon dioxide
EAB	United States EPA, Environmental Appeals Board
EJ	Environmental Justice
ESP	electrostatic precipitator
FLM	Federal Land Manager
FR	Federal Register
IAC	Illinois Administrative Code
IGCC	Integrated Gasification Combined Cycle
Illinois EPA	Illinois Environmental Protection Agency
MACT	Maximum Achievable Control Technology
NAAQS	National Ambient Air Quality Standard
NOx	nitrogen oxides
NSR	New Source Review
PM	particulate Matter
PM2.5	Particulate Matter, 2.5 microns or less in diameter
PM10	Particulate Matter, 10 microns or less in diameter
ppm	parts per million
ppmv	parts per million by volume
SCR	selective catalytic reduction
SO_2	sulfur dioxide
USDOE	United States Department of Energy
USDOJ	United States Department of Justice
USEPA	United States Environmental Protection Agency
USFWS	United States Fish and Wildlife Service